CANADIAN ENERGY
Supply and Demand
1983-2005

Technical Report

NATIONAL ENERGY BOARD

September 1984

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Supply and Demand 1983 – 2005

TECHNICAL REPORT

National Energy Board
September, 1984

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Foreword

The National Energy Board (NEB) was created by an Act of Parliament in 1959. The Board's regulatory powers under the National Energy Board Act include the licensing of the export of oil, gas and electricity, the issuance of certificates of public convenience and necessity for interprovincial and international pipelines and international power lines and the setting of just and reasonable tolls for pipelines under federal jurisdiction. The Act also requires that the Board keep under review the outlook for Canadian supply of all major energy commodities, including electricity, oil and natural gas and their by-products, and the demand for Canadian energy in Canada and abroad.

Since its inception the Board has prepared and maintained forecasts of energy supply and requirements and has from time to time published reports on them after obtaining the views of interested parties. The latest of these reports was issued in mid-1981. Since that time the outlook for energy markets has changed reflecting changing perceptions of the future of energy prices, economic activity, the availability of energy supplies and changes in government policies.

In light of these changes and the concomitant need to reappraise future prospects, the Board in October 1983, invited provincial governments, industry, major energy consumers and public interest groups representing a broad cross-section of the energy community to assist in the preparation of an update of its June 1981 long term projections of energy supply and demand in Canada. On this occasion Board staff was requested to prepare a report without the involvement of Board members in a formal hearing process as had previously been the practice. Some 65 written submissions were received and reviewed in early 1984. The Board extends its thanks to those who contributed to the staff's work in preparing these sets of estimates. It hopes that readers will be provided with a useful review of the country's energy prospects.

This report provides detailed information on the assumptions, methodology and results of the analysis of the supply and demand for energy in Canada. The interpretations and conclusions presented are, of course, those of Board staff. A companion Summary Report can be obtained by contacting the Secretary of the Board at 473 Albert Street, Ottawa, Ontario, K1A 0E5.

TABLE OF CONTENTS

	Page
CHAPTER 1 INTRODUCTION	1
CHAPTER 2 ENERGY PRICING AND MACROECONOMIC ASSUMPTIONS	5
2.1 Domestic Energy Prices	5
2.2 World Oil Prices	6
2.3 Demographic and Macroeconomic Assumptions	8
CHAPTER 3 END USE ENERGY DEMAND	13
3.1 Residential	14
3.2 Commercial	15
3.3 Industrial	16
3.4 Non-Energy Use of Hydrocarbons	17
3.5 Transportation	19
3.6 Total End Use Energy Demand	20
CHAPTER 4 END USE ENERGY DEMAND BY ENERGY FORM, BY REGION	25
4.1 Alternative Energy Forms	25
4.2 Interfuel Competition in Regional Energy Markets	28
4.3 Total End Use Demand by Fuel	35
CHAPTER 5 ELECTRICITY	39
5.1 Total Electricity Demand	40
5.2 Generating Capacity and Energy Production by Region	41
5.3 Implications for National Capacity and Production	49
5.4 Primary Fuels Used to Generate Electricity	51
CHAPTER 6 NATURAL GAS	55
6.1 Supply of Natural Gas	55
6.2 Natural Gas Exports	62
6.3 Primary Demand for Natural Gas	65
6.4 Supply/Demand Balance	66
CHAPTER 7 CRUDE OIL AND EQUIVALENT	69
7.1 Supply of Crude Oil and Equivalent	69
7.2 Primary Demand for Oil	79
7.3 Requirements for Refinery Feedstock	80
7.4 Supply/Demand Balances	83
CHAPTER 8 NATURAL GAS LIQUIDS	87
8.1 Supply of Natural Gas Liquids	87
8.2 Demand for Natural Gas Liquids	89
8.3 Supply/Demand Balances	90

CHAPTER 9
COAL 93
9.1 Supply of Energy from Coal 93
9.2 Primary Demand for Coal 94
9.3 Supply/Demand Balance 94

CHAPTER 10
SOURCES AND USES OF PRIMARY ENERGY 97
10.1 Projections of Primary Energy Demand and Production 99
10.2 Net Exports of Energy 100
10.3 International Perspectives 101

CHAPTER 11
CONCLUSIONS 105

LIST OF APPENDICES A-1

WORD INDEX A-207

CHAPTER 1

INTRODUCTION

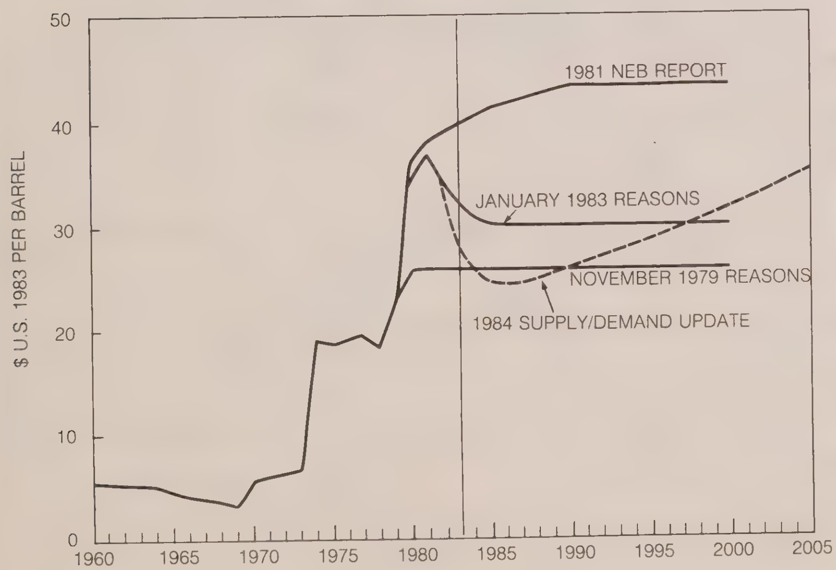
Projections of energy supply and demand in Canada, as elsewhere, have changed frequently and substantially in recent years. Changes in the outlook for energy markets reflect changing perceptions of the future of world oil prices and economic activity. In Canada, perceptions of the outlook for energy markets have also been influenced by the major changes in energy policy that have occurred.

Figure 1-1 illustrates the extent to which perceptions of the future of world oil prices, a key variable influencing projections of supply and demand, have changed since 1979. In the two years separating the issuance of the November 1979 Reasons for Decision[1] and the 1981 NEB Report, the world oil price projected for the year 2000 had increased by some $18 per barrel (constant U.S. 1983 dollars), an increase of almost 70 percent. For the past two years, international oil markets have been characterized by a large excess supply and many analysts are currently assuming that world oil prices will grow only at modest rates through the rest of the century.

Projections of economic activity have also varied considerably in recent years.

Table 1-1 shows that the projected level of Canadian real gross national product (GNP) in the year 2000 has steadily declined in successive Board reports, from $785 billion in the November 1979 Reasons for Decision to $645 billion in the January 1983 Reasons for Decision. We are currently projecting that GNP will attain a level of $670 billion in the year 2000.

Figure 1-1
Average Price of Imported Oil
Recent NEB Assumptions



(1) Decision pertaining to the 1979 Omnibus Gas Export Hearing. For further detail see Appendix 1.

Table 1-1
Projections of GNP in 2000

($1983, Billions)

November 1979 Reasons for Decision	785
1981 NEB Report	710
January 1983 Reasons for Decision	645
1984 Supply/Demand Update	670

These matters are discussed in more detail in Chapter 2. We wish only to note here that, given this kind of volatility in the underlying assumptions of energy market analyses, it is not surprising that the results of those analyses should also be volatile.

The submissions made to the Board indicate that there remains a considerable range of opinion with respect to the probable evolution of world oil prices and of economic activity. In addition, some projections we received were predicated on the assumption that there would be changes in domestic energy policy that would have an impact on future supply and/or demand.

In light of this considerable range of opinion, it would be undesirable and misleading to try to rely on one single estimate of supply and demand for energy in Canada to the year 2005. It is clearly important to have a Reference Case that, after considering all the evidence - including that from submissions, outlines our assessment of the most plausible profile of demand and supply developments. Given the inevitable uncertainties, however, it is also important to assess the plausible range of outcomes for supply and demand for the different energy forms.

In constructing our Reference Case and in assessing what seem to be reasonable upper and lower bounds of plausibility, we have in general assumed that the existing policy framework will remain unchanged over the

projection horizon. This is a standard assumption in most analyses of this kind; it simply reflects the more fundamental premise that we are neither engaged in an exercise to determine the optimal energy policy nor to explicitly assess the adequacy of existing policy. It may well be, however, that the results of our analysis suggest the need for a re-examination of existing policies.

Several factors must be considered in assessing the prospects for energy supply and demand. Energy prices and economic activity, actual and expected, will have an important influence on the outcome. We have assessed the likely impact on Canadian energy markets of world oil prices and economic activity both significantly higher and lower than those used for the Reference Case. Other sources of uncertainty are more difficult to quantify. There is uncertainty, for example, about the impact of relative energy prices and of economic activity on energy supply and demand and, with respect to the supply of oil and gas, there is uncertainty about the size and location of undiscovered resources.

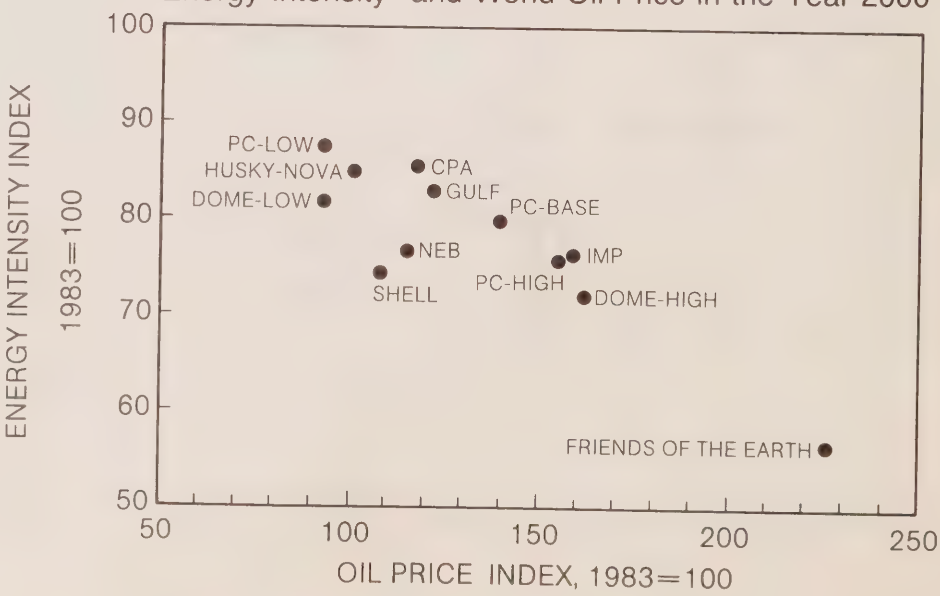
To some extent, uncertainty can be resolved only after the fact. This is inherently true of geological uncertainty, but our knowledge and experience related to the response of energy supply and demand to energy prices is also limited. Energy prices had been relatively low and remarkably stable for many years before 1973 and, in Canada, they have risen more slowly and more smoothly in the past decade than in many other countries. Consequently, we have a relatively limited experience of substantially changing energy prices to use in assessing their impact on energy markets.

Submissions to this update can be used to illustrate the range of opinion which exists both about the impact of prices on energy markets and about geological potential. In Figure 1-2, we have calculated the energy use per dollar of real GNP in the year 2000 implied by the projections of various submittors (indexed to 1983) and plotted this against the world oil price implied by the same submittors' projections for the year 2000 (also indexed on 1983). Figure 1-3 shows the projected oil supply from Western Canada in the year 2000 of various submittors plotted against the world oil price (indexed on 1983) that those same submittors assumed for the year 2000.

Figure 1-2 suggests that, as would be expected, the higher the world oil price assumed in the submission for the year 2000, the lower is the energy use per dollar of GNP, known as energy intensity. It also indicates, however, that even for those submittors who had broadly similar estimates of future world oil prices, there were substantial differences in assessments of the evolution of energy intensity in Canada. The Canadian Petroleum Association (CPA), for example, assumed a higher world oil price than did Husky/NOVA, but the two estimates of energy intensity in 2000 are virtually identical. On the other hand, the estimate of energy intensity shown by Shell is substantially lower than that assumed by Husky/NOVA despite the fact that the world oil price profiles assumed by these two companies are broadly similar.

Figure 1-2

Energy Intensity* and World Oil Price in the Year 2000



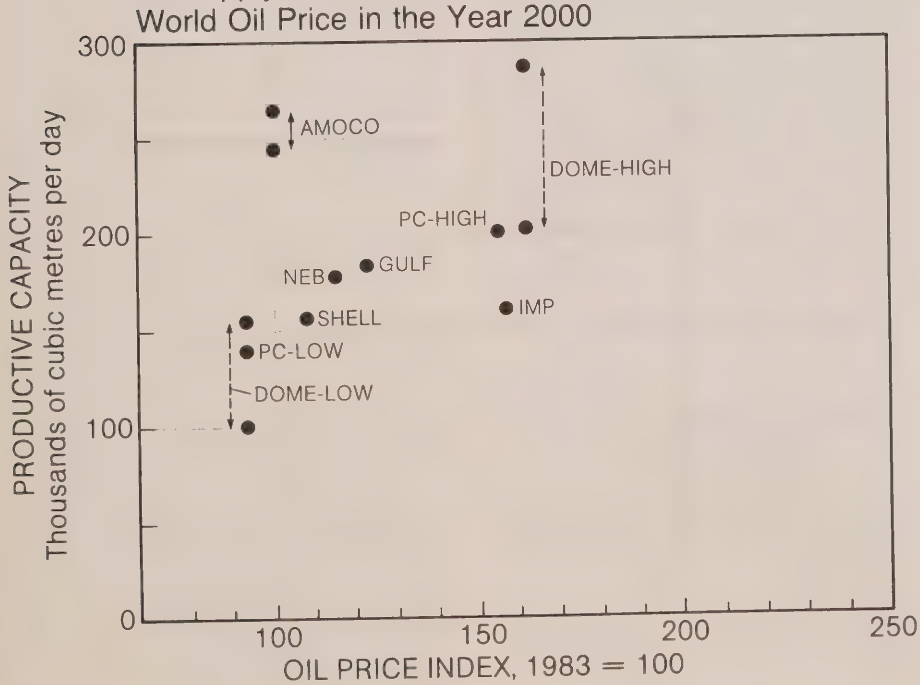
*Terajoules per dollar of real GNP

Figure 1-3 illustrates that, although projections of oil supply from Western Canada tend to rise as the projected price increases, a number of submissions containing major differences in forecast world oil prices nevertheless supplied projections of oil supply that were very similar. This, no doubt, reflects the differing assessments of geological potential among submittors.

The ranges of plausible projections for demand and supply for energy shown in this report should be interpreted as reflecting our best judgment of the boundaries within which demand and supply seem most likely to fall over the projection period, taking account of all sources of uncertainty, given the information available at this time.

In constructing our estimates, we have sought to incorporate as much information as possible using a variety of analytical tools and informed judgment. Thus, while our estimates have, in many cases, been generated using comprehensive statistical models, these results have been modified in light of descriptive analysis and informed judgment based in part on extensive discussions with representatives of the energy community.

Figure 1-3
Oil Supply from Western Canada and World Oil Price in the Year 2000



Report Outline

The report that follows first outlines the underlying assumptions used in constructing the projections. Chapter 2 explains the Reference Case energy pricing assumptions, and the range of prices used to evaluate sensitivity, as well as the demographic and macroeconomic assumptions.

Total energy demand is examined in Chapter 3 for each consuming end use sector and Chapter 4 assesses the extent to which end use demand seems likely to be met by different energy sources, including the likely contribution of alternative energy forms such as biomass and solar.

Having established likely domestic demand levels, the report then examines, on an individual energy commodity basis, the ability of domestic energy sources to satisfy projected demand. Chapter 5 examines the implications of the demand for electricity on generating capacity, energy production and possible surpluses available for export. Chapter 6 discusses natural gas reserves and deliverability and the ability of supply to meet forecast domestic requirements, as well as projected exports. Chapter 7 examines the reserves and productive capability of light and heavy crude oil in terms of domestic refinery feedstock requirements. The supply and supply/demand balance of natural gas liquids is discussed in Chapter 8, while Chapter 9 deals briefly with coal supply and demand.

Chapter 10 contains a summary of the sources and uses of primary energy. The final chapter, Chapter 11, sets out our major conclusions.

CHAPTER 2

ENERGY PRICING AND MACROECONOMIC ASSUMPTIONS

Energy supply and demand are influenced by numerous factors some of which relate to a particular energy form and others of which are pervasive. Among the latter, the prices of energy commodities relative to each other and to other goods and services, and the level of economic activity, are critical. Because assumptions about levels and changes in these variables exert their influence across all energy forms and all end use sectors, we outline in this chapter our assumptions about the path of energy prices and economic activity and its distribution across industries and regions.

Movements in the price of a commodity relative to those for other goods and services exert their effect by inducing substitution away from the commodity whose price has risen. Because the response to price changes frequently involves a switch from one form of capital equipment to another (be it a furnace in a house or a production process in industry), the response of energy demand to price tends to occur relatively slowly over time and is, as a consequence, less immediately obvious than the impact on energy demand of a change in economic activity. The latter exerts its influence directly; a change in the level of production of goods and services translates quickly into a change in the end use energy required.

Our analysis is concerned more with assessing the longer-run trends discernible in energy markets than with predicting the most likely year-to-year path for energy supply and requirements. Our Reference Case is one of a number of plausible paths and there will be year-to-year fluctuations in the underlying variables, such as prices and GNP, and in energy market variables that our analysis does not and is not intended to capture. The band of plausibility that we have identified for energy supply and demand reflects the uncertainties associated with a wide range of factors. To assess the likely width of this band we have been aided by an assessment of the impact on supply and demand of alternative, high and low paths for energy prices, principally world oil prices, and for real GNP.

Sections 2.1 and 2.2 outline the assumptions we have used with respect to domestic energy prices and world oil prices and Section 2.3 examines our assumptions about the evolution of demographic and economic activity factors.

2.1 Domestic Energy Prices

Energy prices faced by end users are conditioned by many varying factors depending on the type of fuel used:

- The prices of refined petroleum products at point of delivery are heavily influenced by international crude oil prices, by domestic pricing and taxation policies, by the costs of transportation to refining centres, and by refining and distribution costs.
- The wholesale price for natural gas that enters into interprovincial trade, east of the Alberta border, is set by the federal government under the provisions of the Energy Administration Act, while the price for gas produced in a province for sale and final consumption within that province falls under the jurisdiction of the corresponding provincial government. Wholesale prices across Canada also include federal taxes and the costs of transportation to the distributor. Prices to end users incorporate, in addition, the costs of distribution and may vary across users, depending on utility pricing practices and other government policies. An example to this effect is the recent agreement between the federal and Alberta governments on a price incentive plan designed to maintain and expand sales of Alberta gas in industrial markets east of Alberta in the next three years.
- Electricity prices are conditioned by the costs of construction, generation, transmission and distribution, and by federal and provincial government regulations. Prices are determined by provincial and local authorities and may vary across end users according to utility pricing practices. In recent years, for example, utilities in Quebec, Ontario and British Columbia have introduced incentive pricing schemes designed to increase sales of electricity to industrial users in those provinces.

In conducting the analysis for this report, we have assumed that existing federal and provincial policies relating to the pricing and taxation of crude oil, petroleum products, and natural gas will remain in force over the projection period. This assumption implies that the refinery acquisition cost of crude oil will be a volume weighted average of conventional old oil at 75 percent of the world price and of new oil at full world price on a quality equivalent basis. As a result, average domestic crude prices over the projection period remain within a range of 90 to 95 percent of the cost of imported crude of similar quality.

This assumption also implies that, in markets east of Alberta, the wholesale price of natural gas will remain in the long term at approximately 65 percent of the refinery acquisition cost of crude oil on an energy equivalent basis. In line with current provincial policy, the wholesale price of natural gas in British Columbia is gradually increased to a target level of 65 percent of the energy equivalent cost of crude oil at the Vancouver refinery gate by 1990. Beyond 1990, we have assumed that the gas/oil price ratio remains at 65 percent. For Alberta, we assumed that the wholesale price of gas remains, over all of the projection period, at about 40

percent of the Edmonton refinery acquisition cost of crude oil on an energy equivalent basis.

Assumptions concerning future electricity prices are more problematical. Prices will be heavily influenced not only by the costs of existing and new additions to capacity and by provincial regulations, but also by utility pricing mechanisms designed to dispose of existing surplus capacity and to keep electricity competitive with other fuels. The price scenario adopted for this report reflects utilities' stated intentions about rate increases in the medium term and assumes essentially constant real prices over the long run.

The implications of the assumptions described above for the relative prices of different energy fuels at the end use level are discussed in Chapter 4 of this report.

2.2 World Oil Prices

The extraordinary oil price increases triggered by the Arab oil embargo of 1973-74 and by the Iranian revolution of 1978 set in motion a number of developments that are having enormous repercussions on international oil markets and, more generally, on world energy markets and the world economy.

The ten years that have elapsed since the first price shock can be divided into two distinct periods: a) the years between the first and second oil price shocks, 1973-1979, characterized by the dominance of world oil production and trade by the Organization of Petroleum Exporting Countries (OPEC), and b) the period from the second oil price shock to the present, characterized by a dramatic decline in world oil demand.

The realization by consuming nations, in the wake of the Arab oil embargo of 1973-74, that oil could be used by key producers not only as a means to pursue the fulfilment of their economic aspirations but also of political goals, led to widespread apprehension about the security of critical OPEC supplies. These fears were compounded by the fact that growth in world oil demand resumed at a brisk pace as the world economy emerged from the 1974-75 recession. Such demand behaviour seemed to confirm the view, widely held at the time, that oil demand tends to be very responsive to fluctuations in economic activity but very insensitive to changes in oil prices.

Thus, the perception that, in a world characterized by dwindling and insecure sources of oil supply, oil production could not be expected to keep pace with the rapidly expanding demand resulting from a growing world economy, led most analysts to anticipate a continuing trend towards sharply higher oil prices in the long run.

Rising world prices, and expectations that they would continue to increase in the future, led in turn to systematic efforts to reduce the dependence of consuming nations on expensive and insecure sources of oil supply. Many countries introduced extensive programs to promote energy conservation and substitution away from oil and large investment projects were undertaken to develop alternative energy sources.

The world economy had not fully absorbed the first price shock when the second wave of large price increases occurred in 1979-80. The price increases further improved the economics of developing non-OPEC sources of energy supplies, accelerated the shift away from energy-intensive goods and services, and led to renewed efforts to conserve energy and substitute other energy forms for oil. The second shock also helped to push the world economy into the deepest recession since the Depression of the 1930s.

The net result of these developments was a sharp reversal in the trend of world oil demand. Between 1979 and 1983, oil consumption in industrial countries dropped by about 20 percent and remained virtually flat in developing nations.

The structural and cyclical reduction in demand for petroleum which occurred, led to a substantial change in the world energy mix in which oil in general, and OPEC oil in particular, steadily lost ground. OPEC's share of world oil trade was further reduced by the attempts of a number of non-OPEC oil exporters to capture an increasing share of a shrinking market. Between 1979 and 1983 OPEC production fell by some 40 percent, and by 1983 it represented only one-third of total world production, compared with over one-half in 1973. Over the same period, OPEC's share of world trade in oil declined to some 60 percent from about 90 percent in 1973.

As a result of these changes, oil increasingly became the marginal fuel among all energy forms and OPEC the marginal supplier of the marginal fuel in world energy markets.

The steady erosion of OPEC's market share, at a time when several of its members were facing severe fiscal and external deficits or large military expenses, forced the organization to cut its prices by five dollars in March 1983 and to control production to keep prices above market-clearing levels.

In addition to the world oil surplus, large surpluses in natural gas and electricity emerged in North America and a number of Western European countries.

Our analysis was conducted on the premise that future oil prices will be driven by both demand and supply factors. We have not attempted to take supply disruptions into account, not because we think they will not occur, but because their timing and impact are virtually impossible to foresee.

The purpose of the analysis is to attempt to find a plausible range for oil prices over the long run. We do not attempt to develop a forecast of likely prices year by year. These will be heavily influenced by variations in demand stemming from cyclical fluctuations in economic activity, shifts in inventory behaviour, changes in the weather, and other short-term factors.

The demand for oil will depend on the course of world economic growth and on the extent to which the enormous price increases of the past decade induce a permanent reduction in the amount of oil consumed per unit of economic activity, income or production. The supply of oil depends on the future profile of discoveries outside OPEC and, within OPEC, on the attitudes of member countries about their production and pricing policies. These attitudes are, in turn, conditioned by their revenue needs, their productive capacities, and on political developments in the Middle East.

Strongly influenced by the events of recent years, market observers have shifted the emphasis in their analyses of future oil prices to the demand side of the equation. Given the state of today's markets, it is hardly surprising that views on oil prices over the remainder of the decade tend to be conditioned more by expectations about the evolution of demand than of supply.

The submissions made to the Board as part of this update show that there is a substantial range of opinion about the likely course of world oil prices. Figure 2-1 shows the range of assumptions used. For the remainder of the 1980s, projections varied from price declines of two percent per year in real terms to increases averaging three percent per year. Beyond 1990, projections ranged from constant real prices to increases of up to five percent per year. Individual submittors' projections are summarized in Appendix 2, Table A2-1. Clearly, reasonable people can differ significantly in their assessment of the relative strengths of the supply and demand factors determining prices.

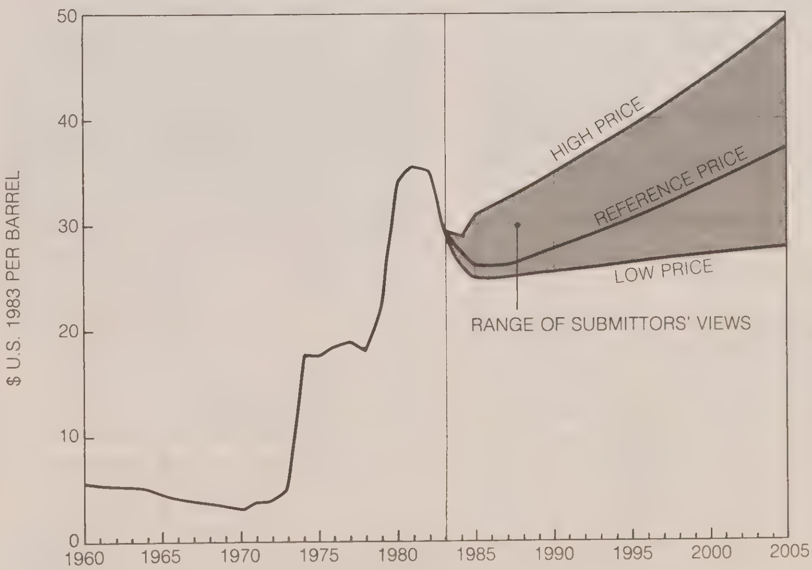
Submittors who expected renewed upward pressure on prices tended to be influenced by an optimistic view of world economic growth, especially about growth in developing countries. On the other hand, others were less certain about the potential for real prices ever regaining the ground lost in the past two years. Their profiles are predicated on the assumption that the link between energy demand and economic growth will be much weaker than it has been in the past. It was generally agreed, however, that it is extraordinarily difficult to assess the extent to which Saudi Arabia, the swing producer, would be willing to increase production in response to higher demand.

In our view, the most plausible price profile to use for the next four years is one in which:

- The official selling price of OPEC marker crude remains constant in nominal terms through 1984 and 1985 at its current level of $U.S. 29 per barrel.
- For 1986 and 1987, the price of the marker crude remains constant in real terms at its 1985 level (i.e., that the price rises at the rate of inflation in 1986 and 1987).

This view reflects the assumption that the world oil market will be characterized by excess supply for some time to come:

Figure 2-1
World Oil Prices



Source: Table A2-1, Appendix 2

- The market currently has excess capacity of some 10 to 12 million barrels per day.
- World economic growth is likely to be moderate on average over the next few years as governments in the industrialized world act to prevent a resurgence of inflation, the United States attempts to resolve the conflict between its monetary and fiscal policies, and the developing world is restrained by limited growth in its exports which, in turn, implies continued difficulty on the part of many countries in servicing their external debt.
- The world still has some way to go before it completes its adjustment to the 1979-80 price shock, so that demand for energy in general and oil, in particular, will be weaker than it has historically been relative to GNP.

Over the longer run, supply factors increasingly come into play. Current assessments suggest that we can expect only modest growth in supplies of non-OPEC oil. Thus, as time goes on OPEC's contribution to world oil trade is likely to increase and world oil demand is likely to press increasingly against productive capacity. As a consequence, there is likely to be a long-run tendency for oil prices to rise faster than inflation.

A combination of lower-than-historical rates of world economic growth in the long term and a slow but steady reduction in oil use per unit of output suggests, however, that pressures on world oil prices are not likely to be excessive. Large increases in world prices are not, in our view, likely to be sustainable for long periods; they would induce supply and demand responses which would, in turn, cause the increases to be short-lived – as demonstrated by recent experience.

These considerations suggest that a reasonable long-term scenario to use in our Reference Case is one in which oil prices rise at a rate of some two percent in excess of the rate of inflation in the 1990s and beyond. We would be hard pressed to defend our choice of two percent against an alternative which projected, for example, a rate of increase of one percent per year. We would not, however, find it difficult to defend our preferred case against one which projected significantly higher increases.

While this Reference Case represents, for us, the most plausible profile for world oil prices at this time, we recognize that others analyzing the factors in play can and do arrive at significantly different conclusions, witness the wide range of assumptions used by submittors. We deem it prudent, therefore, to assess the impact on energy markets of a range of not unlikely cases for world oil prices. Because the submittors to this inquiry represent a broad cross-section of the energy community, it is reasonable to adopt the upper and lower bounds of the range formed by the views of submittors as high and low price scenarios delimiting a band of plausible outcomes.[1]

Table 2-1 shows the rates of change in world oil prices implied by those high and low cases, as well as for our Reference Case.

Table 2-1
World Oil Prices

(Official Price of Arab Light 34° API)

	$U.S. 1983 Per Barrel			Average Annual Growth Rates – Percent	
	1983	1990	2005	1983-1990	1990-2005
High Price	29.54	35.00	50.00	2.5	2.4
Reference Case	29.54	28.00	38.00	–0.8	2.0
Low Price	29.54	26.00	28.00	–1.8	0.5

Source: Table A2-1, Appendix 2.

2.3 Demographic and Macroeconomic Assumptions

The long-run growth of the Canadian economy will be determined by two sets of factors:

- The rate of growth and quality of the labour force and of the capital stock.
- A number of factors that influence the extent to which our capacity to produce is in fact used.

The first set of factors determines the potential productive capacity of the economy. The rate of growth and quality of the labour force depend essentially on the rate of growth in the population and the extent to which the population of working age participates in the labour force. In turn, the rate of growth and the quality of the capital stock, together with the quality of the labour force and the nature and extent

(1) In establishing the range formed by the views of submittors, the price profile used in the Friends of the Earth submission was excluded because it was prepared at a time (1980) when few, if any, analysts expected a significant decline in world oil prices in real terms. Thus, the assumption used by the Friends of the Earth does not capture the decline in real terms experienced by world oil prices in 1982 and 1983 and, as a result, tends to overstate substantially the level of real prices over the projection horizon.

of technological progress, determine the growth path of productivity, i.e., the amount of goods and services produced per worker.

It is virtually certain that the rate of growth in the labour force will be slower in the future than it has been in the past two decades. The population of working age has been growing at a considerably slower pace and, though labour force participation rates have been rising, this is unlikely to be sufficient to offset the decline emanating from a slower rate of growth in population. The prospects for productivity growth are much less certain. Productivity in Canada, after rising at average annual rates of about 2.5 to 3 percent per year in the 1950s and 1960s, has more recently increased at a substantially slower rate.

We assumed that population growth will continue on a downward trend over the projection horizon. This reflects the view that the total fertility rate will stay significantly below the replacement level of 2.1 children per female of childbearing age, and that net immigration will remain at the average level of about 70 000 persons per year recorded in recent years. As a result, Canada's population by the year 2005 is projected to attain a level of about 29 million, an increase of about four million over the present level.

Two driving forces behind the strong growth experienced by the labour force in recent years have been the coming to working age of the post-war baby boom and the dramatic increase in the number of women seeking jobs outside the household. Most analyses concerning labour force participation rates expect continuing increases in the participation of women in labour markets, though at a slower pace than witnessed in recent years. This, combined with modest increases in male participation rates, would suggest that, in the future, we are likely to see more moderate growth in the aggregate participation rate than has occurred in the past.

Slower growth in population, combined with moderate increases in the total participation rate, results in labour force growth slowing from about 1.8 percent per year in the remainder of the 1980s to about 1 percent in the 1990s and beyond, compared with an average rate of 2.8 percent in the last ten years.

We have assumed that productivity growth will recover part way from its very low level of recent years but that it will not regain the relatively high rates of the 1960s. There remain great uncertainties surrounding the causes of the recent productivity decline. It can be attributed in part to the relatively weak growth of demand in the post-1973 period, however it seems that deeper seated factors were at work as well.

In the Reference Case, we assumed that the trend growth rate in labour productivity will average some 1.5 percent per year over the projection period, compared with assumptions of 1.6, 1.2 and 1.1 percent per year used by Data Resources, Informetrica and the Institute for Policy Analysis of the University of Toronto respectively.[(2)] Many uncertainties surround the future prospects for productivity growth. In the long run, labour productivity is increasingly dominated by technological change, an area that is very difficult to assess and project with a reasonable degree of confidence.

In summary, we have assumed that over the next two decades the average rate of potential output[(3)] growth, roughly measured by the trends in labour force and productivity growth, will be somewhat lower than that which occurred in the 1960s and 1970s, of the order of 3 percent per year compared with 4.5 to 5 percent per year.

At the present time, the Canadian economy is operating at a level significantly lower than its potential capacity for production, so that over the next few years it has the ability to grow at a rate significantly in excess of the long-run potential growth rate.

Although the recovery from the 1982 recession has been significant in Canada, and more substantial in the United States, there is considerable uncertainty as to whether the improvement in economic activity will continue to be rapid enough in this country over the medium term to close the gap between capacity and actual production and employment.

Governments in all of the industrialized world are concerned about a resurgence of inflation and are, as a consequence, reluctant to see economic activity expand at too rapid a pace. Interest rates in the United States are, at the time of writing, high and rising, influenced by the policy stance of the Federal Reserve Board and by concerns about the implications of the large longer-run budget deficits in that country. Moreover, rising protectionism among industrial countries combined with extremely large international indebtedness are severely hampering the prospects for growth in the developing world. There is, therefore, considerable doubt as to whether external demand, reflected in demand for Canadian exports, will continue at its recent strong pace. Growth in Canadian domestic demand, on the other hand, has been erratic at best in the past year and there are few signs as yet that business investment in plant and equipment is recovering.

For all of these reasons, it seems prudent to adopt the assumption that

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(2) Data Resources of Canada, *Canadian Review* Spring 1984.
Informetrica, *Workshop 1-84*, April 1984.
Institute for Policy Analysis, University of Toronto, *Policy Study No. 84-2*, April 1984.

(3) Potential output measures what the economy could produce on a sustainable basis using available productive resources.

economic growth will be moderate in Canada over the next few years. In our Reference Case we have adopted the assumption that growth will average 3.4 percent per year to 1990. Under this scenario, the Canadian economy would still be operating somewhat short of its capacity to produce by the end of the decade. For the 1990s and beyond, we assumed a trend growth rate in real GNP of 3 percent per year.

Submittors' views about future economic activity differed appreciably both in terms of the pace and pattern of GNP growth over time. Several submittors assumed average annual rates of growth of 3 percent or more throughout the projection horizon but a number of them expected a less buoyant growth performance, at rates in the neighbourhood of 2.5 percent per year. Similarly, some submittors assumed a growth path weaker in the 1980s than in the 1990s, while others expected relatively robust gains in the remainder of the 1980s proceeding at a somewhat slower pace in the 1990s and beyond. Individual submittors' projections are summarized in Appendix 2, Table A2-2.

Recognizing the possibility of a medium-term growth path weaker than that of the Reference Case we have assessed the implications for energy demand of economic growth in Canada at rates averaging some 2 percent per year over the remainder of the 1980s, proceeding at somewhat faster rates in later years. We have also assessed the implications for energy demand if economic growth were to proceed at a significantly faster pace in the 1980s and to approach capacity production by 1990. Thus, our high growth scenario has economic activity growing at rates averaging some 4.5 percent per year through 1990 and 3.2 percent per year thereafter (Table 2-2).

Table 2-2
Growth in Real GNP

	\$1983, Billions			Average Annual Growth Rates – Percent	
	1983	1990	2005	1983-1990	1990-2005
High Growth	389	529	848	4.5	3.2
Reference Case	389	490	763	3.4	3.0
Low Growth	389	447	676	2.0	2.8

Source: Table A2-2, Appendix 2.

The use of energy in production processes is unevenly distributed across industries. Although goods production[4] currently represents some 29 percent of total output in Canada it accounts for about 32 percent of the energy consumed in the country. Moreover, within the goods producing sector, almost two-thirds of the energy used is concentrated in mining, iron and steel, pulp and paper and chemical industries, which make up only some 16 percent of goods production. It is evident, therefore, that energy demand can be powerfully affected if there is a shift in the distribution of output towards or away from the energy intensive industries.

During the 1970s service industries grew at a faster pace than those producing goods, so that the share of goods-producing industries declined from 35 percent of total output in 1971 to 29 percent in 1983. The speed at which the mix of industrial output will change in the future is uncertain. It will depend on demographic, economic and technological factors and on government policies.

If it is difficult to determine a reasonable aggregate growth path for the economy, it is even more difficult to know what to assume about the distribution of that growth. Currently, there is widespread concern about the future of the traditional resource-based, exporting industries in Canada. Some analysts believe that because of deep-seated structural problems, these industries are in a period of decline. Others argue that the current state of affairs is more a reflection of the fact that these industries bore the brunt of the 1981-82 recession and that, as they introduce labour and energy-saving innovations, they will in time resume their traditionally substantial role.

Submittors generally assumed a continuing trend towards a service-oriented economy, though significant differences of opinion on the speed and extent of the transition were evident. Thus, for example, while some foresee a substantial shift away from goods production taking place over the next 20 years, others argued that in Canada any such shift is likely to be gradual and spread over a longer time horizon than in countries less dependent on resource-based, export-oriented industries.

We have assumed that the goods-producing part of the economy will sustain its position relative to total output perhaps moderately increasing its

[4] The definition of goods production used in our projections of energy demand excludes the output of agriculture, fishing, trapping and of electric power and gas distribution utilities, while the definition of service production excludes the output of transportation, storage and communications. Because of data problems or technical considerations, the energy demands of these industries are either treated separately, for example transportation, or allocated to one of the other major energy consuming sectors.

share. This partly reflects the view that the problems of basic manufacturing industries are more short-run and cyclical than longer-run and structural. It also reflects the assumption that declining rates of growth in population would imply a more slowly growing service sector than we have recently seen. It is entirely possible, though, that the impact of population change would be more on the nature of the services demanded than on the quantity.

The pattern of energy use in Canada is also importantly influenced by the regional pattern of economic activity and growth.

Important changes have occurred in the regional distribution of economic activity in Canada in recent years. Most notable was the relative strength of the western provinces in the years following the energy price increases of the 1970s. In the past two years, however, there has been a tendency for growth to shift back towards central Canada. In line with most submittors who provided information about their expected regional distribution of activity (Appendix 2, Table A2-3), we assumed that there would be a resumption of a shift in activity towards the West and, to some extent, towards the Atlantic provinces. We have assumed that increased exploration and development of East Coast offshore energy resources would support more buoyant growth in the Atlantic region than has previously occurred. In the West, relatively stronger growth is expected to occur, spurred by a revival of oil sands projects, construction of heavy oil upgrading facilities, and the expansion of the railway network in response to higher freight rates (Table 2-3).

The requirement for energy by end users clearly depends on a number of factors related to the growth and distribution of production of goods and services. While it is likely that the path of aggregate economic activity will be the dominant factor, it is critical to recognize that the profile for energy demand can vary significantly depending on what assumptions are made with respect to the industrial and regional distribution of economic activity.

Table 2-3
Total Real Domestic Product

Average Annual Growth Rates - Percent

	1983-1990	1990-2005
Atlantic Canada	3.4	3.1
Quebec	3.0	2.7
Ontario	3.1	2.7
Prairies	3.5	3.3
British Columbia and Territories	3.8	3.5
Canada	3.3	2.9

Source: Table A2-3, Appendix 2.

CHAPTER 3

END USE ENERGY DEMAND

Energy is used to satisfy a variety of end uses:

- Space heating and cooling in buildings.
- Lighting and appliance use in homes.
- Process heat and power for machinery in industry.
- Motive power for transportation vehicles.
- The manufacture of products for direct use by consumers and as materials in the further production of final goods.

Because the factors determining the amount of energy used for each of these purposes differ, it is convenient to discuss end use demand in terms of distinct sectors of the economy:

- Energy used in households and farms is included in the residential sector.
- The commercial sector includes all service producing industries except transportation. It includes governments and educational and health care institutions.
- The industrial sector comprises most of the goods producing industries. The use of hydrocarbons to produce petrochemical products, asphalt and other miscellaneous products is treated separately and termed non-energy uses.
- Energy used in transporting goods and services and people is aggregated into the transportation sector.

In 1983, energy use was distributed across these groups of activities as shown in Table 3-1. All energy forms are used to some extent in each of the residential, commercial, and industrial sectors. The transportation sector uses refined petroleum products almost exclusively and non-energy uses operate on the basis of natural gas, natural gas liquids (NGL) and crude oil.

This chapter assesses the prospects for total energy use, all energy forms taken together, in each sector, for the country as a whole. Chapter 4 considers how this total end use demand has been and is likely to be distributed across regions and across the different energy forms. Subsequent chapters consider primary demand for energy by fuel and in total. Primary demand, as distinct from end use (or secondary) energy demand, includes intermediate use of energy to generate electricity or produce steam, as well as energy used in supplying final consumers with their requirements.

Developments over the past two decades are best characterized by three sub-periods:

- The period from the early 1960s up to 1973 was characterized by stable and low energy prices and rapid growth in economic activity. Correspondingly, end use demand for energy increased very rapidly throughout the period, especially in the services producing part of the economy. There was an enormous increase in building to provide all kinds of services to a rapidly growing population. Moreover much of the construction was in large buildings, requiring the installation of electricity-using equipment, such as elevators, and greatly expanded use of ventilating and air conditioning equipment.
- In 1973-78 there were extraordinary increases in real energy prices, and economic activity grew at a more moderate rate (a moderation caused in no small measure by the energy price shock of 1973). These factors tended to moderate energy demand; growth in end use requirements slowed considerably by comparison with the preceding period.
- The period 1978-82 was characterized, on average, by negligible growth in real economic activity and by a further substantial increase in real energy prices. This period was, of course, dominated by the great recession of 1982. Between 1980 and 1982 end use demand including transportation demand declined by eight percent. Indeed, end use energy demand in 1982 was only marginally above the level it had reached in 1977.
- The recent recession had an especially strong impact on energy demand in the goods producing industries and in the transportation sector of the economy. In the industrial and transportation sectors energy demand declined by 11.6 and 11.1 percent respectively between 1980 and 1982.

Table 3-1
Distribution of End Use Energy Demand, 1983

	Petajoules	Shares-Percent
Residential	1266	20
Commercial	819	13
Industrial	2030	32
Transportation	1701	26
Non-Energy	592	9
Total	**6407**	**100**

Succeeding sections of this chapter outline our views on the likely course of end use energy demand in the various sectors over the projection period. All of these projections reflect our views that:

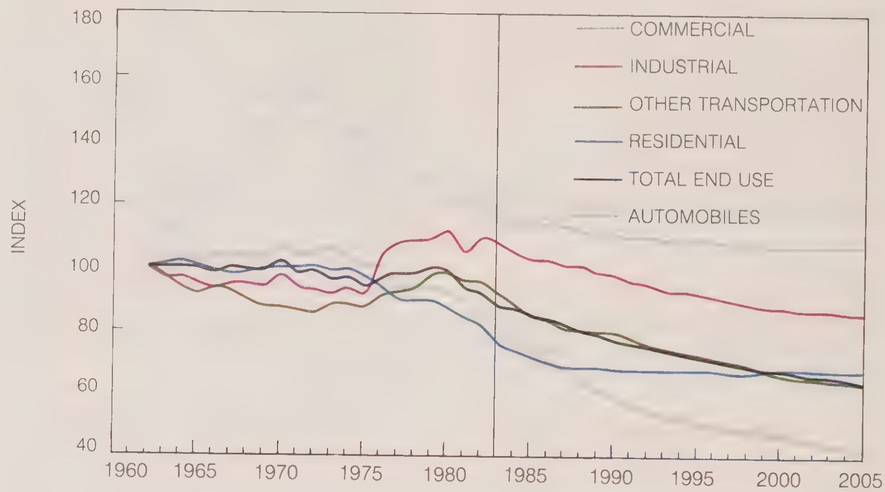
- There is likely to be considerable further energy conservation, reflected in continuing declines in the intensity of energy use, for some years to come (Figure 3-1).

- This conservation occurs despite the fact that the energy price profile used in our Reference Case shows no increases, in real terms, until the 1990s.

It is useful, therefore, to outline the rationale for this view at the outset and to review briefly the extent to which conservation has already occurred.

In both commercial and residential sectors energy intensity has declined substantially since 1973. The contrast between the pre and post embargo periods is particularly striking in the commercial sector, where the intensity of energy use had increased dramatically in the 1960s and early 1970s. The intensity of energy use in the industrial sector has remained virtually constant since the early 1960s. Unlike the numbers for other sectors, those for industry do not suggest any marked change in the intensity of energy use before and after 1973. The stability in the aggregate industrial energy intensity index is, as discussed below, the net result of large but offsetting changes.

Figure 3-1
Energy Intensity by Sector (1962 = 100)



In the transportation sector, the decline in energy use per car has been quite marked since 1973, as consumers purchased more fuel efficient, smaller cars, and as they travelled less. The intensity of energy use in transporting goods, on the other hand, is currently similar to levels experienced in the early 1960s, as efficiency improvements have been only marginal.

Underlying our view that there remains considerable scope for conservation at existing energy prices is the premise that, while there is some scope for energy use to respond quickly to price increases through the implementation of housekeeping measures such as turning down thermostats, the speed and extent of conservation is governed by the rate at which capital equipment is replaced. Such equipment is long lived and can be expensive to replace or refit before the end of its useful life. In the residential and commercial sectors, for example, the extent of energy use depends on the insulation characteristics of dwellings and buildings, the nature of furnaces and the energy efficiency of appliances.

Many of the buildings, appliances, industrial equipment and motor vehicles currently in use were put in place in the years before energy prices had risen dramatically. As a consequence, their energy efficiency is relatively low. Even though new capital equipment being put in place embodies a much more efficient energy using technology, its impact on energy use will occur gradually over a relatively long period. It follows that it will be some time yet before we have completed our adaptation to energy price increases that have already occurred. This is not to suggest that conservation is independent of future price increases. Figure 1-2 in Chapter 1 shows that, as would be expected, there tended to be a relationship between the energy price profiles used by submittors and their projected intensity of energy use.

3.1 Residential

In addition to prices, residential demand for energy is driven by growth in the number of households and real personal disposable income as well as by consumer preferences. The former affects the extent to which the housing stock will increase and, as a consequence, the demands for energy for space heating and basic household appliances. Income growth also influences spending on what may be

termed discretionary appliances. The influence of energy prices – past, present and future – is pervasive, affecting as they do the structural characteristics of housing and the energy efficiency of space heating and other appliances.

Table 3-2 summarizes recent and prospective rates of growth in key variables influencing household energy demand, as well as past developments in end use energy demand and our assessment of its future course.

It is highly likely that residential demand for energy will grow much more slowly over the next 20 years than it has in the past:

- It is virtually certain that the number of households will grow at a much more modest rate than it has since the early 1960s, by about one percent per year compared with past increases of about three percent, reflecting the slowdown in population and labour force growth.
- Under our assumptions about productivity and labour force growth, real income will grow more modestly than it did in the 1960s and early 1970s.
- The energy efficiency of households is likely to improve over time as the proportion of new, more energy efficient, houses in the housing stock gradually increases and as greater use is made of more energy efficient space heating and other appliances.

The evidence suggests that there is considerable scope for conservation at existing energy prices, but this will take place gradually as old appliances are replaced with more efficient new ones and as the housing stock is increasingly comprised of retrofitted and new dwellings.

Our Reference Case assumes that energy use in the residential sector will amount to some 1460 petajoules in 2005, an increase of only 12 percent over the 1983 level.

Table 3-2
Energy Demand by Households Average Annual Growth Rates

(Percent)

	1962-73	1973-83	1983-90	1990-2005
Households	2.8	3.0	1.5	1.0
Real Income per Household	2.7	0.3	1.3	1.7
Real Energy Price	0.4	4.6	–1.1	0.2
End Use Demand	2.8	0.6	–0.5	1.0
Demand per Household	–0.1	–2.4	–1.9	0.0

Levels

	1973[1]	1983[1]	1990	2005
End Use Demand (Petajoules)	1231	1304	1262	1461
Demand per Household (Gigajoules)	196	154	135	134

(1) Normalized for weather.

Table 3-3
Index of Energy Intensity in Households Comparison of Submittors' Views

(1983 = 100)

	1990	2000
Shell	90	82
Petro-Canada	102	96
Gulf	97	95
TCPL	98	93
Imperial	87	79
Friends of the Earth	—	49
NEB	88	86

3.2 Commercial

This category comprises all service industries in the economy except transportation; it includes energy use by such diverse enterprises as corner grocery stores, hospitals, banks, and consulting engineers. Since data are available only by aggregate energy use in the commercial sector, we cannot assess in detail the source of energy demand.

Energy use in commerce grew very rapidly in the 1960s but increases have moderated in recent years as growth in output among service industries has slowed and the intensity of energy use has declined.

We have projected economic growth in this part of the economy to be somewhat slower in the future than it has been in the past, reflecting the impact of a more slowly growing population. There will not be the same need in years to come to increase the institutional infrastructure (such as educational and health care institutions) as there was in the past. Some have argued, however, that, as the population ages, the mix of institutions will change, requiring further development.

Although our economic projections imply a more slowly growing service economy in the future, its rate of growth will still be substantial as declines in the growth of health and educational institutions are offset to some degree by an increase in other services. It seems likely, for example, that there will be fairly strong growth in business services comprising what many have called the information economy.

We have assumed a modest continuing decline in energy intensity in the commercial sector, reflecting the assumption of some retrofitting of existing buildings, continued housekeeping conservation and the assumption that new construction and equipment will be more energy efficient than the existing stock. The evidence is that the energy efficiency of new office buildings currently being constructed is dramatically improved over that of buildings constructed in the 1970s. It has been estimated, for example, that today's state of the art buildings consume about 100 kilowatt-hours per square metre per year compared with some 500 kilowatt-hours per square metre per year in the average building constructed in the 1970s. Although these improvements are dramatic, they will not have a commensurate effect on energy intensity because of the very long life of existing buildings.

Our projections for total energy demand and for energy intensity in the commercial sector are shown in Table 3-4. We project growth in energy demand to be some 2 percent per year for the rest of this decade and close to 2.5 percent per year in subsequent years to 2005.

3.3 Industrial

For our purposes we define the industrial sector of the economy to include all goods producing industries with the exception of agriculture, electric utilities, and the petrochemical industry.

Table 3-4
Commercial Energy Demand Average Annual Growth Rates

(Percent)

	1962-73	1973-83	1983-90	1990-2005
Commercial RDP	5.5	3.1	2.7	2.7
Real Energy Price	–2.0	5.4	–0.5	0.2
End Use Demand	9.1	0.7	2.2	2.4
Intensity	3.4	–2.3	–0.5	–0.3
Levels				
	1973	1983	1990	2005
End Use Demand (Petajoules)	762	819	955	1363
Intensity (Megajoules per $1971)	16.1	12.8	12.4	11.9

Within the industrial sector, the use of energy is highly concentrated among a small subset of industries. Figure 3-2 shows the distribution of energy use among sub-sectors . Almost two-thirds of industrial use occurs in the mining, iron and steel, pulp and paper, and industrial chemicals industries, which together account for only 16 percent of industrial output.

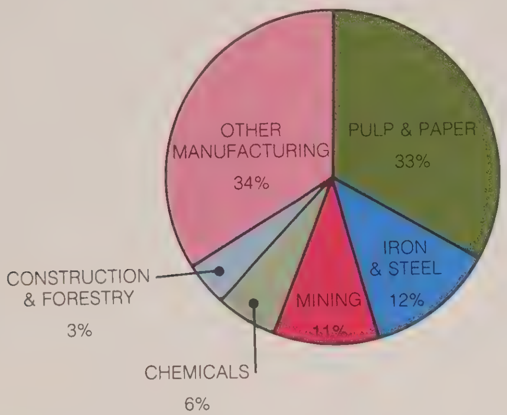
In aggregate there has been virtually no change in the intensity of energy use since 1978. If, however, one views a switch from oil and gas to wood wastes as conservation, then the intensity of energy use in industry has declined by as much as four percent. In individual industries, however, the experience has been extraordinarily diverse as indicated in Table 3-5.

Table 3-5
Intensity of Energy Use by Industry

	Energy Intensity[1]		Percent Change
	1978	1982	
Pulp and Paper	462	516	12
Iron and Steel	312	310	–1
Industrial Chemicals	238	301	26
Mining	67	76	13
Forestry	34	36	8
Construction	8	6	–30
Other Manufacturing	35	33	–6
Total Industry	60	60	1

(1) Megajoules per 1971 dollar of industrial output.

Figure 3-2
Energy use in the Industrial Sector, 1982



Source: Statistics Canada
Catalogue Number 57-003

There have been substantial declines in intensity, for example, in the construction industry and in other manufacturing, but large increases in industrial chemicals and in mining. Using a more disaggregated approach, the Task Force on the Canadian Industrial Program of Energy Conservation (CIPEC) reported substantial energy conservation between 1972 and 1982 in the industrial processes covered by the program.

Given the concentration of energy use among a small number of industry sub-groups and the diversity of their experience to date, the prospects for industrial energy use need to be assessed by examining key groups in some detail. Such an assessment would include, in addition to the prospects for industry growth, an examination of the likely capital investment profile and the energy using characteristics of new equipment. Increasing attention is being paid to this area by energy market analysts.

Our assessment of the evidence, including discussions with submittors who had assessed the industrial demand for energy in some detail, is that there is a considerable potential for further improvement in energy intensity and that we have only begun to see the impact of the recent energy price increases. Business fixed investment in Canada has, since 1981, been at very low levels. As investment spending grows in the future, industry will be putting in place machinery and equipment that is much more energy efficient than that which it replaces. The electric motors on the market today for example, are much more efficient than were those manufactured a few years ago. Further, energy costs relative to total production costs have risen dramatically in recent years for all industries and, in future, the choice of industrial processes will be much more sensitive to their energy using characteristics than they have been in the past. For example, thermo-mechanical pulping processes are being considered for use in the pulp and paper industry as a much more energy efficient technology than current processes for producing pulp. Moreover, the evidence suggests that the cogeneration of electricity with steam in large industrial plants is currently economically feasible and can be expected to increase significantly.

Reflecting these factors we project that energy demand in the industrial sector will grow at a rate considerably lower than that projected for industrial output. Whereas our projection of economic activity suggests that output in the industrial sector will rise at an average annual rate greater than 4 percent in the years to 1990 (Table 3-6), we are projecting growth in energy demand more than a full percentage point lower per year. Industrial energy demand in our Reference Case is projected to be some 3450 petajoules by the year 2005, an increase of some 70 percent above its estimated 1983 level. This reflects the relatively strong growth path which we have projected for industrial output; energy intensity is projected to decline over the same period by some 20 percent.

3.4 Non-Energy Use of Hydrocarbons

Petrochemical and other non-energy uses of hydrocarbons amounted to about 590 petajoules in 1983. Over two-thirds of this use was for petrochemical production and, of the remaining 208 petajoules, about one half was used in the production of asphalt (Table 3-7).

Table 3-6
Industrial Energy Demand Average Annual Growth Rates

(Percent)

	1962-73	1973-83	1983-90	1990-2005
Industrial RDP	6.0	0.2	4.1	3.3
Real Energy Price	–0.8	6.6	–1.4	1.2
End Use Demand	5.2	0.4(1)	2.6	2.4
Intensity	–0.8	0.5(1)	–1.5	–0.9
Levels				
	1976	1983	1990	2005
End Use Demand (Petajoules)	1980	2030	2422	3454
Intensity (Megajoules per $1971)	57	59	54	47

(1) Growth since 1976.

Table 3-7
Non-Energy Uses

(Petajoules)

	1973	1983	1990	2005
Petrochemicals				
Natural Gas	93	233	331	372
Oil	82	98	76	76
NGL	–	53	126	166
Total Petrochemicals	174	384	533	614
Asphalt	138	112	129	166
Other Non-Energy Uses	102	96	113	148
Total	**414**	**592**	**775**	**928**

The world petrochemical industry is characterized at present by large excess supply stemming both from a slackening rate of growth in demand (resulting partly from the large increases in product prices in the 1970s) and the substantial expansion of capacity in Canada and abroad in recent years.

Petrochemical feedstock use in Canada has more than doubled in the decade since 1973. Most of the increase has occurred in the use of natural gas, and significant amounts of NGL are now being used, whereas none were used in the early 1970s. There has been only a marginal increase in the amount of oil used as feedstocks.

Demand for petrochemical products recovered in 1983 and can be expected to continue to grow with world economic activity, albeit at rates lower than those that have occurred in the past. On the supply side, the prospect exists for a substantial expansion in production in the Middle East. Accordingly, the prospects for the Canadian industry and, correspondingly, its expansion plans are considerably more modest than they were even two years ago. Projections of petrochemical feedstock demand are particularly uncertain:

- The future of the industry in Eastern Canada, primarily oil-based, will be heavily influenced by federal government decisions on the recommendations of the recently published Petrochemical Industry Task Force Report. This Task Force recommended market responsive pricing for fuel and feedstocks, and government assistance for the oil-based petrochemical industry in Eastern Canada to enable use of alternative feedstocks. The federal government has indicated that it would consider assisting oil-based producers to achieve feedstock flexibility. It has not changed feedstock pricing policies.
- The timing of new plants assumed to come on stream and announcements with respect to additional plants or the re-activation of deferred construction plans will be heavily influenced by both the domestic and international environment, which in turn will be affected by the extent to which new production capacity is constructed in other areas of the world, particularly the Middle East.

We are projecting significant growth in petrochemical demand for feedstock concentrated in natural gas and NGL. Our projections assume that the use of oil will decline as the petrochemical industry in Eastern Canada partially

converts from oil to the use of NGL as alternative feedstock.

In the years to 1990, the demand for NGL is driven by the start-up this year of an additional ethane-based ethylene plant in Alberta and the assumed increasing use of NGL as feedstock in substitution for oil. Further increases in ethane requirements are projected in the mid-1990s, when an additional ethylene plant is assumed to come on stream.

Growth in demand for natural gas as a feedstock is more gradual than that for NGL. We assume that four new ammonia plants will be constructed during the projection horizon, only one of which is firm (currently being constructed by C-I-L Inc. in Ontario). In addition, we assume that one further methanol plant comes on stream in 1990.

Demand for asphalt increased rapidly at an average annual rate of seven percent between 1962 and 1973, remained relatively stable from 1973 to 1978, and declined between 1978 and 1982. In 1982 alone, asphalt demand declined by more than 15 percent, reaching its lowest level in 10 years. With an improved economy in 1983, however, asphalt consumption increased by 3.4 percent, the first increase since 1979.

Economic recovery will provide some impetus to growth in the demand for asphalt, but various factors are likely to result in moderate growth during the projection horizon: moderate activity in new road construction, the use of computerized control programs for road building and repairs, the recycling of old asphalt and the use of other materials in the asphalt mix.

Other non-energy uses include the demand for lubricating oils and greases, petroleum coke, naphtha specialties, and other non-energy petroleum products. Lubricants and greases account for about 40 percent of this combined total. The demand for these products as a group is projected to increase at an average annual rate of two percent during the forecast period.

Our projections for non-energy use of hydrocarbons are summarized in Table 3-7. Growth in petrochemical feedstock demand is particularly marked in NGL and to a lesser degree in natural gas, offset by a modest decline in the use of oil.

3.5 Transportation

Next to the industrial sector, the transportation sector is the largest consumer of energy, which in this case consists virtually entirely of oil-based products. Some 80 percent of the energy used in transportation is consumed by road vehicles.

Energy used for transportation grew at a rate of about six percent per year in the 1960s and early 1970s, slowed to an average annual rate of just over three percent between 1973 and 1978 and, since then, has declined at a rate of about one percent per year. In the road segment this slowing rate of growth was the combined result of several factors:

- There was a gradual slowing in the rate of growth in new vehicle sales. Indeed in the years since 1978 new sales declined at an average rate of four percent per year.
- The share of small cars in new car sales increased from 49 percent in 1978 to 75 percent in 1982; it currently stands at about 60 percent.
- As a result of the changing mix of cars and improved fuel efficiency standards, the average fuel efficiency of the automobile stock has increased by close to four percent per year since 1978.
- In the truck fleet, the proportion of more efficient, diesel powered vehicles, has been increasing.

We are projecting a further marginal decline in energy used in road transportation through 1990 with very modest growth recurring subsequently. Underlying this projection is the assumption that energy demand for use in automobiles will continue to decline moderated by an increase in fuel use by trucks.

For automobiles our views are conditioned by a number of considerations:

- Though we assume that new car sales will pick up considerably from recent levels, they are likely to be constrained by modest growth in household income and by recent increases in the real cost of operating cars. We estimate that the real cost of operating an automobile has risen by about 20 percent since 1980.
- Our projected growth in new car sales is not much greater than the assumed scrappage of existing vehicles, so that the car stock grows by only about one percent per year for the remainder of this decade compared with about four percent per year in the years between 1962 and 1983.
- We assume faster rates of growth in the car stock in the 1990s but that sales will be constrained both by the slowing rate of growth in numbers of households and by increasing saturation of the market.
- In our view the share of small cars in new car sales is likely to continue to increase, rising from a share of 60 percent in 1983 to 70 percent by the mid-1990s.
- The sales-weighted fuel efficiency of new car sales is assumed to increase substantially, by some 6 percent per year, in the years 1984 and 1985 as the United States Environmental Protection Agency's Corporate Average Fuel Economy standards are im-

plemented. Improvements in fuel efficiencies after that date are more speculative in nature and we have assumed, somewhat arbitrarily, that the average fuel efficiency of new models would increase by 2.5 percent per year until 1990 and by about 0.5 percent per year in the following decade. These assumptions, combined with the projected shift towards smaller models, imply an increase in the average efficiency of the car stock of close to 4 percent per year in the years to 1990, and of about 2 percent per year from 1990 to 2005.

With respect to all of these factors, there were considerable differences of opinion among submittors. On fuel efficiencies, for example, assumptions ranged from an improvement of about 50 percent by 2000 relative to 1983 levels (Shell) to a 25 percent improvement (Gulf). These numbers compare with our assumption that there would be about a 40 percent improvement by the year 2000.

We are projecting a reversal of the recent decline in total energy use by trucks in the remaining years of this decade, followed by stronger growth in the 1990s. The projection reflects the offsetting effects of higher growth in the truck stock, and improvements in fleet fuel efficiency of about two percent per year.

The share of diesel fuel used in trucks is projected to continue to increase, as it has for some years now. We have the share of diesel fuel in road sector energy demand rising from some 16 percent in 1983 to about 26 percent in 2005.

In our view the energy used in road transportation is likely to continue to consist overwhelmingly of gasoline and diesel fuel. It seems probable that there will be increasing use of propane and compressed natural gas (labelled NGV – natural gas for vehicles) and that these conversions will mainly occur in commercial fleets. The share of propane and NGV in road sector energy demand is projected to rise to about 5 percent by 2005, a small share, although a considerable increase over the current level of 0.3 percent.

Use of energy in air transportation increased dramatically through the 1960s and 1970s, but the industry has now matured and future growth is projected to be negligible in the years to 1990 and modest thereafter (about 2.5 percent per year). This reflects the view that: growth in passenger kilometres will be modest, partly as a result of the impact of telecommunications on business travel; load factors will continue to rise; and aircraft fleet fuel efficiencies will improve at a rate of about 2 percent per year.

Both Air Canada and CP Air observed in their submissions that continuing improvements in energy efficiency in air transportation were likely, reflecting the implementation of such measures as engine modifications to existing aircraft, replacement of old aircraft by new, more energy efficient fleets, and improved air traffic control procedures.

There is considerable uncertainty about the impact on energy demand of deregulation of the air industry. Increased competition could lead to the use of more fuel efficient aircraft, but this could be offset by increased travel to perhaps a wider range of destinations.

Rail and marine transportation currently account for about five percent each of transportation energy demand. Given our projected growth path for the economy, energy used in these sectors can be expected to grow apace. We are not confident, however, that we have adequately accounted for the impact of the recent revisions to the Crow's Nest Pass grain freight rates. The new measures will significantly increase the capacity of the rail system, and hence energy use could be somewhat greater than we have projected.

Rail electrification on a major scale seems unlikely; the high cost of rail electrification and uncertainty with respect to government financial assistance have made railway companies unwilling to make firm commitments to electrification.

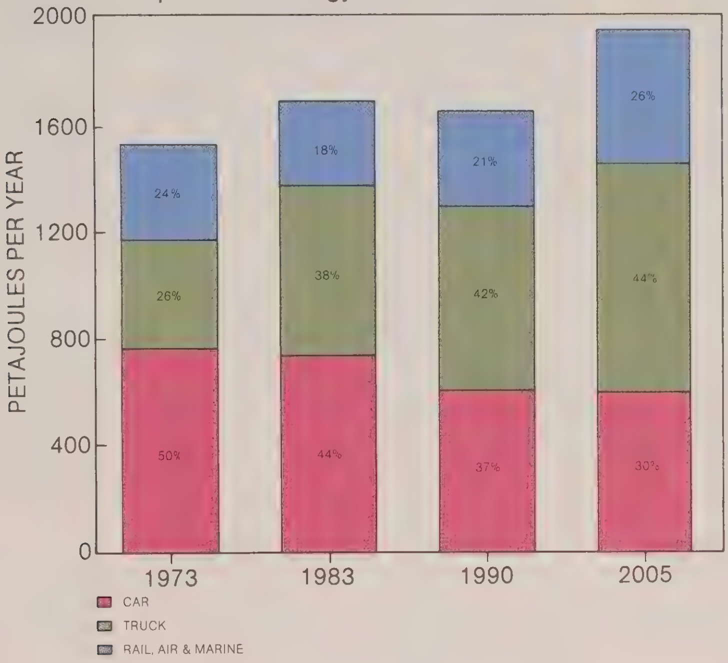
Figure 3-3 illustrates the changing distribution of energy use in the transportation sector.

3.6 Total End Use Energy Demand

Our Reference Case projection of total end use energy demand in Canada is summarized in Figure 3-4. Although growth in total end use demand gradually picks up over the next 25 years it remains, in our Reference Case, significantly slower than occurred in the years before 1978. Total energy use in Canada rises under this scenario, from a level of about 6400 petajoules in 1983 to some 9200 petajoules in 2005, an increase of some 44 percent. Though large in absolute terms this growth occurs during a period in which we have assumed growth in real GNP of some 97 percent. Thus, this projection implies a decline in the overall energy intensity of the Canadian economy of 27 percent over the projection horizon, from 48 megajoules per dollar of real GNP in 1983 to 35 megajoules in 2005.

The strongest growth during the projection horizon is projected to occur in the industrial and commercial sectors; hence their shares of end use energy demand, especially that of the industrial sector, increase significantly by 2005. Transportation and residential demand decline in relative terms and non-energy uses continue to account

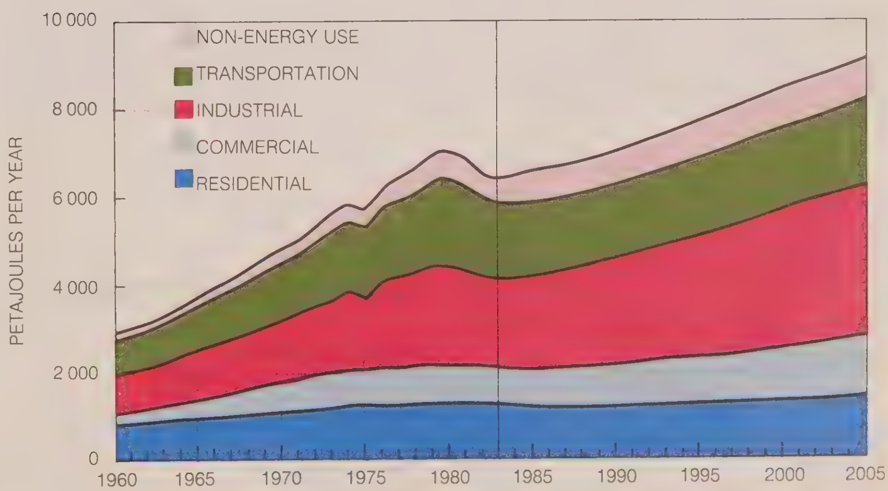
Figure 3-3
Transportation Energy Demand, Canada



Source Table A10-2, Appendix 10

for about ten percent of end use demand.

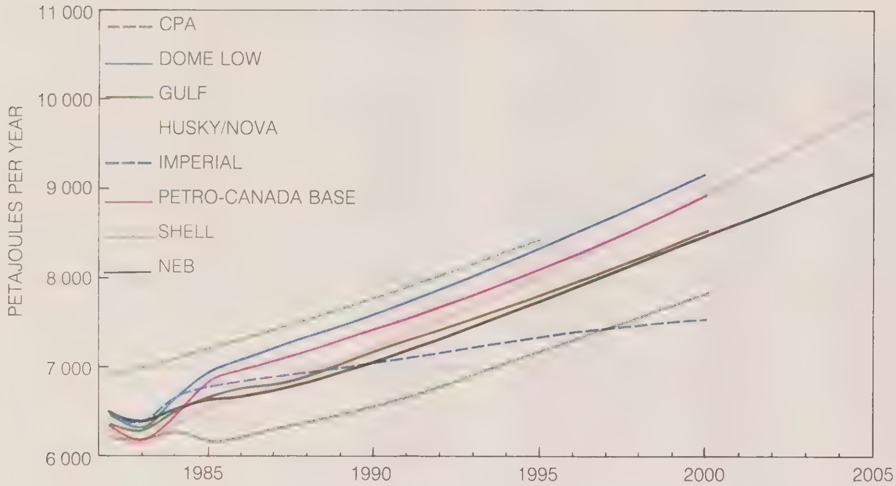
Figure 3-4
End Use Energy Demand, Canada



Source: Table A3-1 and A3-2, Appendix 3

Although our Reference Case represents our best assessment of the prospective evolution of energy demand it is only one of a number of plausible scenarios. Even abstracting from some of the more imponderable factors that could affect it there are, as we have shown, significant differences of opinion among analysts with respect to energy prices, economic growth and, equally importantly, with respect to their assessments of the impact of these variables on energy demand. In this latter regard, it is interesting to note that a study by Data Resources of Canada using our assumptions about economic growth and energy prices, projected end use demand to be about ten percent higher in 2005 than our

Figure 3-5
Projections of End Use Energy Demand, Canada



Source: Table A3-2, Appendix 3

Table 3-8
Change in Demand from Reference Case in 2005

(Percent)

High Economic Growth	+8
Low Economic Growth	−9
High Energy Price	−5
Low Energy Price	+4

Table 3-9
Plausible Range for Energy Demand

(Petajoules)

	1990	2005
High	7 480	10 300
Reference Case	7 072	9 168
Low	6 730	8 320

estimate. Figure 3-5 compares our forecast of end use energy demand with those of submittors.

Our estimates of the impact on the Reference Case of the alternate economic growth and energy price cases noted in Chapter 1 are summarized in Table 3-8.

Assuming our alternate growth and price tracks are reasonable representations of the likely outer limits of those variables, the results suggest that economic activity could cause our demand profile to vary more than would prices.

We have repeatedly expressed the view throughout this chapter that our Reference Case is predicated on the judgment that energy demand in Canada is likely to be heavily influenced by significant and continuing conservation in major energy using sectors. In our view, there is some risk that conservation will be somewhat less than we have estimated, and energy demand correspondingly higher. Figure 1-2 suggests, for example, that our projected aggregate energy intensity in 2000 is somewhat lower than that of submittors with similar price assumptions. Accordingly, we have adopted an upper bound to our range of energy demand which is somewhat higher than that suggested by the high growth case. Table 3-9 summarizes the resulting end use demand profiles.

The high end of the range has energy demand growing at 2.2 percent per

Table 3-10
NEB Projections of Total End Use Energy Demand

(Petajoules)

	1983	1990	2000
1981 NEB Report	7 393	8 452	10 485
1984 S/D Update	6 407	7 072	8 489
Percent Difference	−13	−16	−19

year in the period 1983 to 2005, compared to 1.6 percent in the Reference Case and 1.2 percent in the low case.

The Reference Case projection of end use demand is significantly lower than that published in the 1981 NEB Report as shown in Table 3-10.

The current projection is lower largely as a result of the impact of the substantial decline in economic activity in 1982. In addition to the impact of lower economic activity on all end uses of energy, we now assume that conservation will have a much more significant impact on demand, despite the fact that oil prices are expected to be lower than previously projected. The gradual impact of much more energy efficient plants in the industrial sector of the economy, as well as higher fuel efficiencies of transport vehicles and a greater shift towards smaller cars are the main reasons for additional demand reductions.

CHAPTER 4

END USE ENERGY DEMAND BY ENERGY FORM, BY REGION

Price and availability of different energy forms vary appreciably from one region to another. Excluding the transportation sector, which is virtually all oil-based, oil supplies a substantial share of demand in Eastern markets; hydroelectric resources are abundant in Quebec, Manitoba and British Columbia, and natural gas is heavily used in the Western provinces (Table 4-1).

The use of wood in home heating and in some industrial applications has enjoyed a resurgence in recent years in the Atlantic provinces and British Columbia and, to a lesser extent, in Quebec. Apart from wood, however, energy forms other than oil, gas and electricity are used to only a very limited extent.

The sharp rise in the prices of conventional energy sources in recent years and the recognition that many conventional sources are non-renewable have led to increased interest in, and assessment of, the potential for more widespread use of alternative forms of energy, many of which are still undergoing research and development.

The next section outlines our views on the prospects for increased use of such alternative sources of energy as wood, solar, and municipal solid wastes. Section 4.2 discusses the prospects for the use of different energy forms in non-transportation uses in regional markets. The chapter concludes by summarizing the implications of our analysis for the outlook for energy demand by energy form in Canada.

4.1 Alternative Energy Forms

Interest in the potential for increased use of alternative energy forms, many of them renewable, has led in recent years to a number of government programs to subsidize research, development and demonstration projects and to various studies of their technical and economic feasibility. One such study, "2025: Soft Energy Futures for Canada", recently completed by the Friends of the Earth, was submitted for use in the preparation of this report.

We have used this study, along with information from a variety of other sources, including the federal Department of Energy, Mines and Resources (EMR), the Economic Council of Canada and the Ontario Ministry of Energy, in our assessment of the prospects for alternative energy forms outlined below.

Assessing the prospects for new energy forms is particularly difficult and inevitably speculative. In many cases the technologies are still in the research and development stage, so that any assessment of future costs is highly speculative and often site specific, which precludes its general application. In other cases, technologies are already developed, but their high cost militates against their widespread use. In such cases either rapid increases in the prices of conventional fuels, or a currently unforeseen cost-reducing technological breakthrough is needed to make the use of such alternatives economically feasible.

Estimates of the feasibility and likely penetration of alternative energy forms are critically dependent not only on one's assessment of the likely costs of such energy sources, but also on what one assumes about the future price profile of conventional energy forms. Moreover, many studies are conducted with a view to determining the social desirability (i.e., the desirability from the point of view of society as a whole) of using particular forms of energy as opposed to determining their potential attractiveness to users.

The evaluation of social desirability is based on a comparison of the long-term marginal costs of alternative fuels in order to choose the use of the least-cost alternative. The commercial decision of choosing one particular alternative energy form, on the other hand, is based on existing market prices. Market prices are, however, often based on average costs and can also differ from social costs because they are affected by various taxes and subsidies. It can, therefore, be quite rational, from a decision maker's point of view, to make a

Table 4-1
Non-Transportation Fuel Shares in Domestic Energy Markets, 1983

(Percent)

	Atlantic	Quebec	Ontario	Prairies	British Columbia(1)	Canada
Coal	4	2	11	1	1	5
Oil	46	34	19	15	16	23
Gas	—	13	38	59	25	33
Electricity	25	40	22	16	23	25
Wood	19	9	5	3	34	10
Other	6	2	5	6	1	4
Total	100	100	100	100	100	100

(1) Figures include Yukon and Northwest Territories.

choice which is different from the socially desirable, least-cost alternative.

The Soft Energy Study submitted to us is more in the nature of an assessment of what the outlook for energy use in Canada would be if all energy forms were priced at their social costs than an assessment of what that outlook is under actual pricing practices. The authors assumed, for example, that electricity would be priced according to the costs of installing new generating capacity and that Canadian natural gas would be priced at its full substitution value for oil. Their assumed price profiles for gas and electricity were, as a consequence, considerably higher relative to the price of refined petroleum products than is likely to be the case under actual pricing practices.

Although studies of this kind are a most useful, indeed essential, part of the process of policy formation, they do not provide the kind of information that makes it possible to assess the likely path of future developments in energy markets because prices are not determined in the way these studies assume. For a study of the kind in which we are engaged, the relevant prices are the actual prices that prevail in the market. These differences notwithstanding, the Soft Energy Study is valuable because it brings together and evaluates a wealth of information on the potential for energy conservation and on the outlook for the costs and technology of alternative energy forms.

In addition to assuming a price determination process different from that which prevails, the authors based their analysis on the assumption that world oil prices would grow at a very rapid rate, much higher than we, or any other submittors, assumed. The Canadian oil and gas prices assumed in the Soft Energy Study for the year 2000 were, respectively, some 70 percent and 140 percent greater than the prices that we assumed even in our high price case. (The outlook for world oil prices was of course, much different when this study was initiated several years ago; an expectation of continuing price increases from existing high levels was generally typical of that time.) These two assumptions led them to conclude that a large proportion of Canada's energy needs could be supplied from renewable energy sources by the year 2000, most of it in the form of liquid and solid fuels produced from biomass, primarily wood.

Table 4-2 summarizes the information on the estimated costs of various alternative energy forms that we were able to gather from a variety of sources. The cost estimates included in this table, having been gathered from numerous sources, embody quite different assumptions and were constructed according to different methodologies. They are intended to show only rough orders of magnitude. For comparison, we have also included the price of Canadian oil assumed by the soft energy authors as well as the price range we have used in this study.

These estimates indicate that barring technological breakthroughs, and as long as an adequate supply of natural gas is available at prices which we have assumed, it is most unlikely that use of active solar energy or of wood gasification and liquefaction will occur in the foreseeable future. There does, however, appear to be some scope for expanded use of municipal solid waste, wood for combustion, and perhaps some peat for combustion, during our projection horizon.

Although the physical potential for wood production in Canada is large, its realization would require much more widespread use of intensive forest management than is currently practiced and its use as an energy form is, in our view, likely to be severely constrained by economic factors. Similarly, though the physical resource potential of peat is very large, resources tend to be in isolated areas, making their harvesting and use expensive. A study by the Ontario Ministry of Energy[1] indicated, however, that peat obtained from bogs close to pulp and paper mills could be competitive with oil and natural gas when used in mills having solid fuel firing capacity.

Further we assume that as the disposal of municipal solid waste in larger urban centres becomes gradually more expensive, a greater number of steam plants using solid waste as fuel will be built adjacent to these centres.

Thus, our best guess about the outlook for alternative energy sources under our pricing assumptions is that:

[1] "Potential Demand for Peat" dated June 1983.

Table 4-2

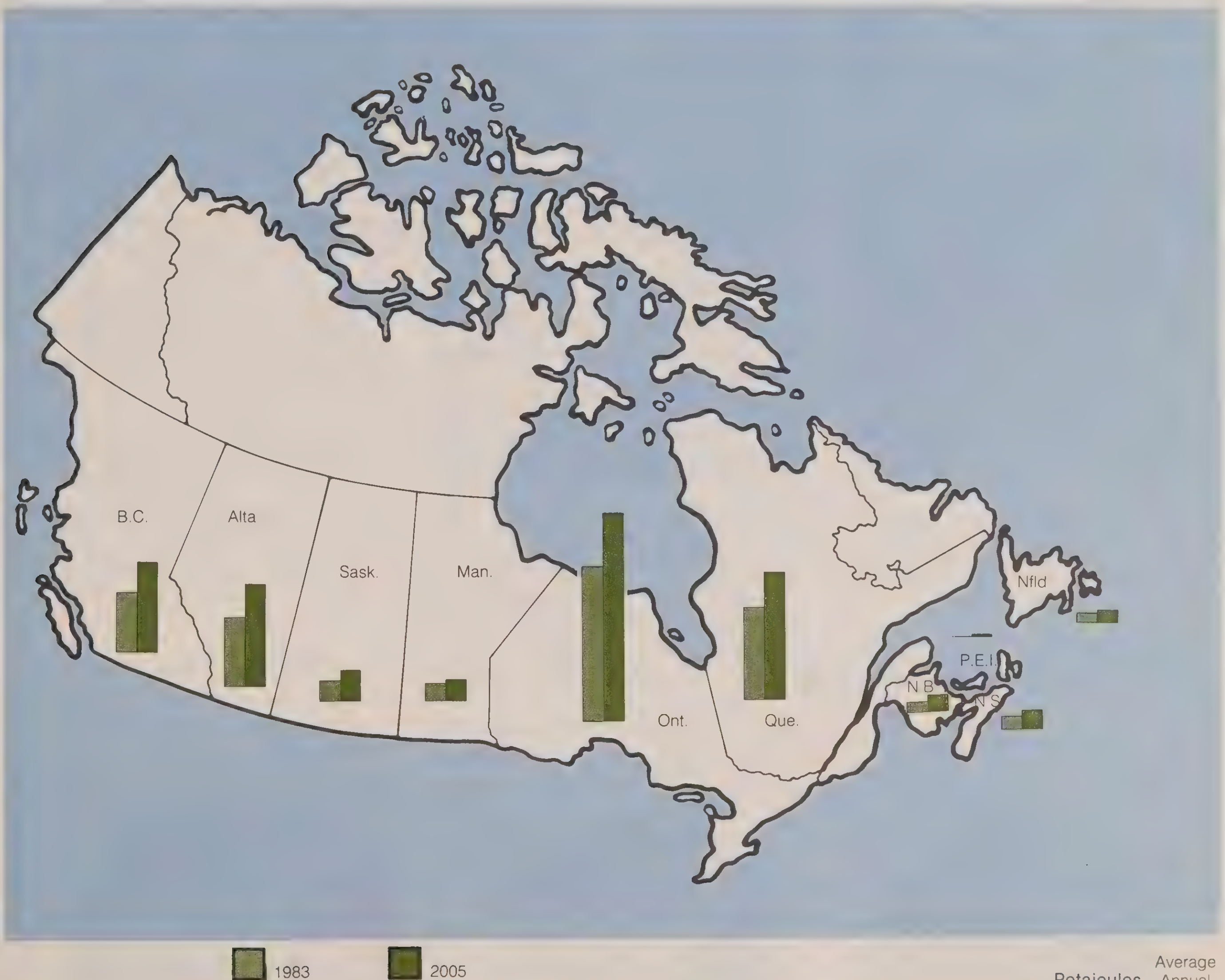
Costs of Energy from Alternative Energy Forms[1]

($1983 per Gigajoule)

Crude Oil at Toronto (year 2000)	
Friends of the Earth	15
NEB	5-9
Natural Gas at Toronto (year 2000)	
Friends of the Earth	14
NEB	3-6
From Wood (present)	
– Ethanol	19-23
– Methanol	21
Active Solar (present)	26-46
(year 2000)	21
Municipal Solid Waste (present)	3-9
Wood – Residential (present)	2-6
– Industrial (present)	1-4

(1) These estimates are not directly comparable because of the variety of assumptions and methodologies used in their derivation.

Figure 4-1
Regional End Use Energy Demand



	Petajoules 1983	Petajoules 2005	Average Annual Growth (%)
Canada	6407	9168	1.6
Quebec	1340	1850	1.5
Ontario	2260	3092	1.4
Manitoba	226	297	1.2
Saskatchewan	281	414	1.8
Alberta	976	1546	2.1
B.C. & Terr.	859	1302	1.9
Newfoundland	117	163	1.5
P.E.I.	17	21	1.0
Nova Scotia	179	257	1.7
New Brunswick	151	226	1.8

- There is likely to be modest further expansion in the use of wood in households mainly in rural areas, to 120 petajoules in 2005 from about 100 petajoules in l983.
- Use of wood waste and pulping liquor in the pulp and paper industry will increase marginally from 380 petajoules in 1983 to about 440 petajoules in 2005.
- Other alternative energy sources are likely to continue to contribute a relatively small proportion (about one percent) of the Canadian energy demand in 2005. Hence we project demand to be about 100 petajoules.

Although small in relative terms, our projected increase in the use of alternative energy forms represents a significant expansion over amounts currently in use.

4.2 Interfuel Competition in Regional Energy Markets

Energy use in Canada is concentrated in the two largest provinces of Ontario and Quebec and is likely to continue to be so over the projection period (Figure 4-1). Reflecting our assumption that growth in economic activity in the future will tend to be concentrated somewhat more in the West and in the East, our projections show some shift in the distribution of end use energy demand to those regions.

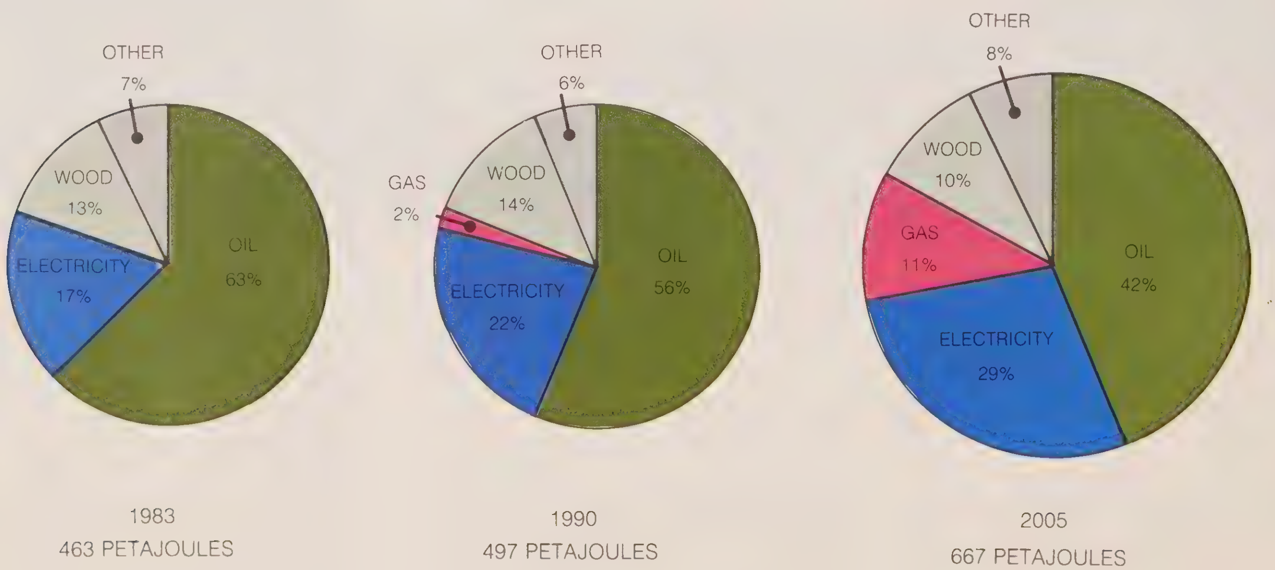
Atlantic Region

In the Atlantic region there has recently been a significant shift away from oil to electricity and wood. It is estimated that some 17 percent of households are currently using wood as a principal fuel and another 23 percent are using wood to supplement other fuels. In the industrial sector, oil use has declined from 52 percent in 1978 to 33 percent in 1983, mainly as a result of increased use of wood wastes, which currently supply some 24 percent of industrial requirements.

We are projecting a continued shift away from the use of oil-based products, a shift that is likely to accelerate in the 1990s coinciding with the availability of Scotian Shelf gas (Appendix 4). We assume that natural gas will capture a significant market share when and where it is available. According to the Nova Scotia government, surveys have indicated a high degree of acceptability of natural gas as an energy source in the province.

We are projecting a continued increase in the market share of electricity,

Figure 4-2
End Use Energy Demand, Atlantic



Source: Table A4-1, Appendix 4

particularly in Newfoundland and New Brunswick. The prospect for additional electricity penetration in industrial use is, however, hard to evaluate, depending as it does on the extent of further expansion and modernization of pulp and paper mills. Modernization has already led to the use of thermo-mechanical pulping processes that consume about three times the electricity per ton of output compared to kraft or chemical pulping processes.

Wood now enjoys a good degree of acceptability in Atlantic markets, and we assume continued penetration in residential and industrial markets in the next few years, assisted by off-oil programs. Over the longer term however, a levelling in demand, and hence a declining share, is projected, as easily accessible supplies are used up.

The projected level and distribution of end use demand in Atlantic markets (including transportation requirements) is shown in Figure 4-2.

Quebec

In Quebec, electricity is a major competitor in the residential, commercial and industrial sectors. Hydro-Québec currently has substantial surpluses of hydroelectricity that it is actively marketing domestically and in the United States. At the same time, distributors of natural gas are promoting increased gas use as service areas are gradually extended. The result is a head-on conflict, as both fuels attempt to displace remaining oil use.

Considerable uncertainty exists as to the outcome of this competition and its implications for the shares of natural gas and electricity. In our Reference Case, we assume that Hydro-Québec will be successful in its marketing initiatives, as it has been in the recent past.

In residential and commercial markets, gas distributors and Hydro-Québec have been aggressively competing for conversions from oil. In residential markets, for example, Hydro-Québec has been very successful in selling hybrid (electricity-oil) heating systems. It has offered direct financial assistance to consumers to cover conversion costs over and above those paid by the federal government under the Canadian Oil Substitution Program, and as well is currently pricing electricity competitively with oil. We assume that these practices will continue and that they will be successful in disposing of surplus electricity. (Table A4-3 in Appendix 4, presents our outlook on relative energy prices and resulting fuel shares.)

Gas distributors are also offering financial assistance to homeowners to convert off oil. As a result, gas is currently capturing about half of all conversions in its service area. Over the longer run, we assume some decline in the degree of gas penetration in existing dwellings. In new housing markets, electricity currently captures about 80 percent of potential customers, and it is likely that this will continue.

The industrial sector currently uses about half of non-transportation end use energy consumed in Quebec. Accordingly, it represents a prime market for Hydro-Québec and for natural gas utilities. As a result of aggressive marketing programs on the part of both electric and gas utitities, combined with federal off-oil incentives, the share of the industrial market held by heavy fuel oil has been reduced to about 16 percent from 28 percent in 1978.

Hydro-Québec initiatives to market electricity have included substantial financial assistance towards the capital cost of converting industrial oil-fired boilers to electricity. Discounts of up to 50 percent are being offered to encourage the use of electricity in plant expansions and new plants, and surplus electricity is being priced at 90 percent of the price of heavy fuel oil and coal.

Federal government programs to encourage the use of natural gas in industrial markets include contributions towards the costs of converting from oil. The federal and Alberta governments have recently agreed to introduce volume-related discounts for a three year period. Gas distributors have introduced programs such as conversion assistance over and above the federal grants from the Industrial Conversion Assistance Program, and the Quebec government has removed the provincial sales tax on natural gas.

We assume that both electricity and natural gas will further penetrate industrial markets, mainly at the expense of heavy fuel oil. Electricity is projected to expand its share more rapidly as a result of our assumption that Hydro-Québec will successfully dispose of current electricity surpluses. Electricity use will also increase as the aluminum industry grows and perhaps also as a result of the introduction of new electricity-intensive industrial processes. Hydro-Québec has suggested, for example, that thermo-mechanical pulping processes could be used in more than 20 percent of wood pulp production after modernization in this industry is complete.

In the long run, we project a continuing slow expansion in the electricity share in Quebec based on the assumption that its competitive position will improve as gas and oil prices rise (Appendix 4). This conclusion is, of course, contingent on our assumption that electricity prices remain constant in real terms in the long term.

Given our projection of growth in total end use energy in Quebec, the view of interfuel competition outlined above implies that energy use will be distributed across energy forms as shown in Figure 4-3.

Ontario

Considerable competition between natural gas and electricity also exists in Ontario although it is less intense than in Quebec.

Ontario Hydro has recently initiated a series of marketing programs with the aim of promoting the wider but wise use of electricity. Its objective is to increase electricity's share of end use energy demand (excluding non-energy use) from 16 percent currently to 20 percent by 1990. After 1990, it is expected that such marketing efforts would cease in order to avoid any requirement for additional generating capacity.

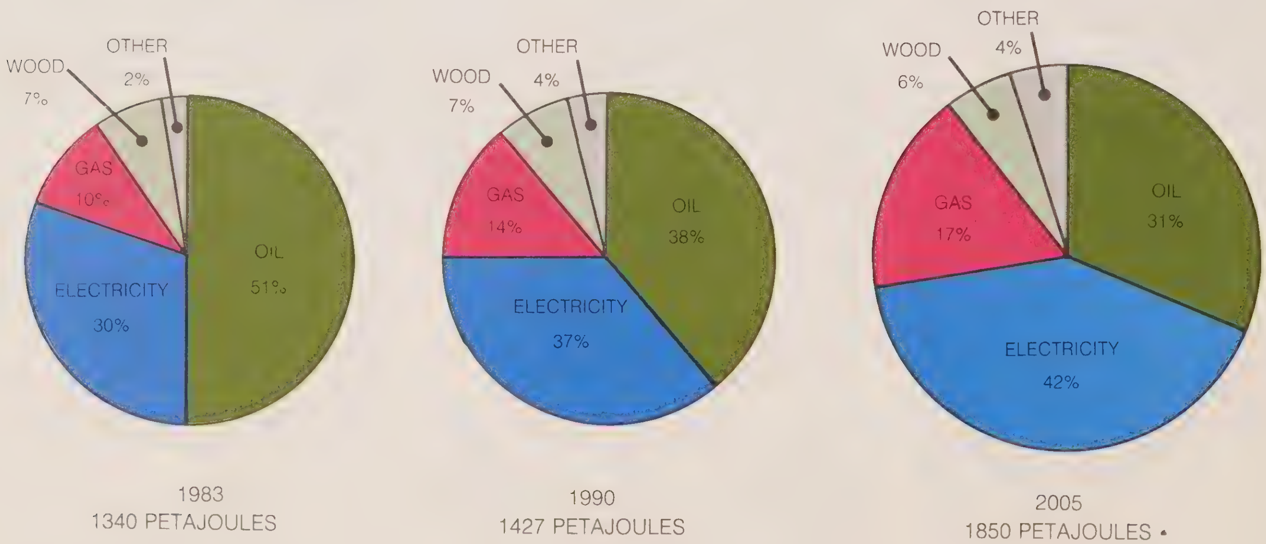
The evolution of fuel shares that we have assumed is consistent with the achievement of Ontario Hydro's 20 percent objective. Considerable uncertainty exists, however, since Ontario Hydro is still in the process of defining its marketing program, and we may have overestimated the extent of electricity use at the expense of oil.

Ontario households have made a major shift away from oil towards natural gas and electricity in recent years. In 1983 only 25 percent of homes were still using oil as the principal heating source, while 56 percent used natural gas, and 16 percent electricity.

The Government of Ontario publishes information on the costs and benefits to consumers of various space heating alternatives. The most recent information[2] indicates that consumers can attain considerable savings by switching from oil, with natural gas options generally involving somewhat higher savings than those using electricity.

(2) Ontario Ministry of Energy, *The Homeowner's Off-Oil Heating Conversion Decision, the Costs and Benefits*, 1983 Edition.

Figure 4-3
End Use Energy Demand, Quebec



Source: Table A4-1, Appendix 4

The price assumptions used for that analysis are similar to those used in our work, and accordingly, we assume that Ontario consumers will continue to switch away from oil mainly to natural gas and, to a lesser extent, to electricity and wood (Appendix 4). The rate of conversions may be slower than in the recent past, however, if soft oil prices continue. Over the longer term, we project continued penetration by electricity as a result of an improved competitive outlook, and growth in electricity consumption for appliance use.

In industrial markets, considerable uncertainty exists about the prospective evolution of fuel shares. There were substantial differences among submittors' projections of the industrial fuel distribution. In the recent past, electricity, steam from nuclear plants, wood wastes and coal have all gained share at the expense of both heavy fuel oil and natural gas. In fact, the share of heavy fuel oil has been cut in half since 1978, and currently retains only six percent of the market.

We assume that in the next few years, some discounting of electricity prices will occur consistent with Ontario Hydro's efforts to market surplus power on an interruptible basis. In addition, the recently negotiated volume-related discounts for natural gas will apply over the next three years. Prices for interruptible natural gas and electricity are very similar and, while we assume that both of these initiatives will serve to further expand the shares of gas and electricity, we find it difficult to assess the likely gains of each fuel, particularly since there is only limited room for further movement away from oil.

Other marketing initiatives on the part of Ontario Hydro may also be implemented. The direct process heating market (metal melting for example), where electrical technologies can provide such advantages as efficiency improvements and better control, is one area where programs to increase electricity use may well be undertaken.

Given our outlook for energy prices and Ontario Hydro's marketing initiatives, we assume that electricity will increase its share of industrial markets, rather than remaining flat or declining, as various submittors have assumed. We also project further penetration by natural gas, supported by initiatives by the federal and Alberta governments and by marketing strategies on the part of natural gas utilities.

With respect to competition from coal, we have assumed that natural gas would not suffer any significant load loss, although submittors indicated that some conversion to coal by cement plants has recently occurred. In our view, environmental concerns, as well as equipment and handling costs, will outweigh the significant price advantage offered by coal.

We do not expect heavy fuel oil to play a major role in the future. Ontario's traditional surplus of heavy fuel oil has declined significantly due to refinery rationalization. Several submittors indicated that they felt the surplus could grow over time as a result of the use of lower quality crude and increased throughput, with correspondingly higher yields of heavy fuel oil. For our part, we assume that heavy fuel oil supply will continue to decline as a result of upgrading and further refinery rationalization, and that in the event there are surpluses, they would tend to be exported. However, many large industrial plants have dual fuel capability, and given the right pricing and availability conditions, industrial use of heavy fuel oil could be higher than we have assumed.

End use energy demand by fuel resulting from our analysis of the prospects for interfuel competition in Ontario is summarized in Figure 4-4.

Prairie Provinces

Energy use in the Prairie provinces is dominated by the use of natural gas, although hydroelectricity has grown significantly in Manitoba in recent years. In residential markets, for example, 26 percent of homes in Manitoba now use electricity as their principal heating fuel. Such penetration has been fostered by a freeze in the rates charged by Manitoba Hydro from 1978 to 1983. Natural gas also continues to do well in new housing markets even though it no longer offers a substantial price advantage over electricity. The competitive position held by natural gas is expected to improve somewhat in the next few years, but to gradually deteriorate over the long term. Hence, we see natural gas maintaining its share of residential markets in the remainder of this decade, but declining slowly in the 1990s as the share of electricity slowly increases.

In Manitoba industrial markets, gas distributors indicated that a substantial load loss had occurred in recent years, partly as a result of plant closures. Consistent with such closures and with the increasing competitiveness of electricity, the share of natural gas declined from about 37 percent in 1978 to 30 percent in 1983. Electricity has gained during this period, and is expected to continue to do so in the future, as its competitive position improves under our pricing assumptions.

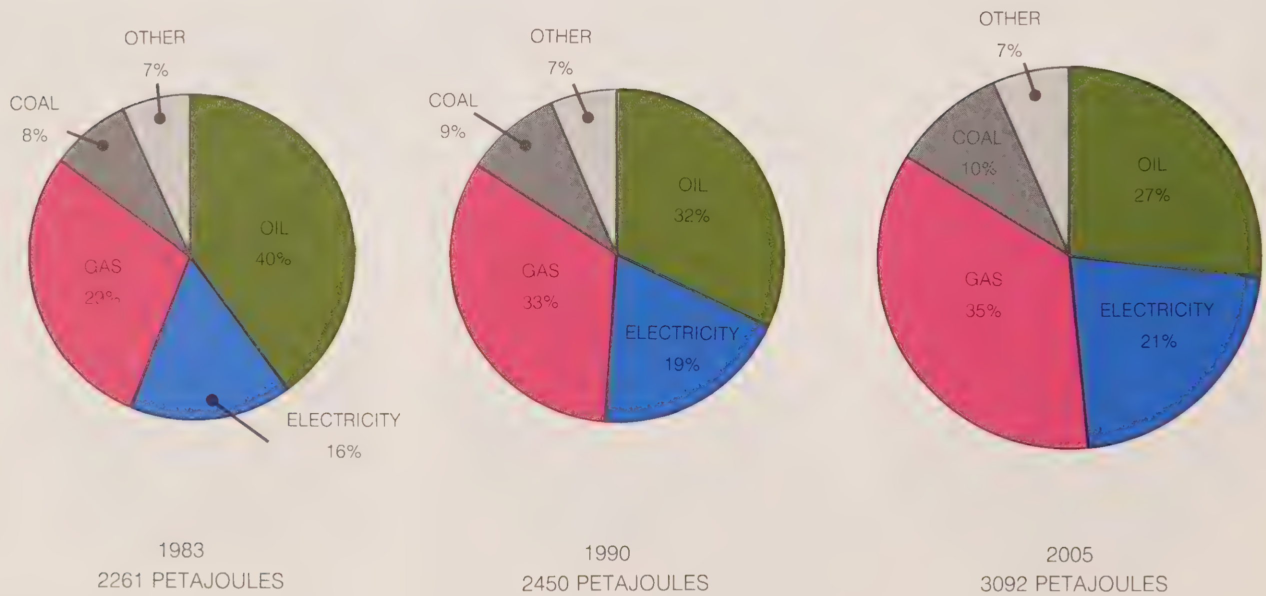
In Saskatchewan, natural gas has a substantial price advantage over other energy forms and has a large share of residential, commercial and industrial markets. In its submission, the Government of Saskatchewan indicated that the Saskatchewan Power Corporation is expanding the gas distribution system to rural markets, and this is expected to increase the share held by natural gas at the expense of oil. We assume that natural gas will retain its

dominant position in residential, commercial and industrial markets over the forecast period, so that demand is determined by the outlook for demographic and economic growth and for conservation.

Natural gas is also used extensively in Alberta, where it currently supplies about 65 percent of non-transportation end use requirements. As in Saskatchewan, natural gas is likely to continue to be the predominant fuel in the residential, commercial and industrial sectors. We assume, however, that electricity will continue to penetrate industrial markets. This reflects the view expressed by the Electric Utility Planning Council of Alberta (EUPC) that electricity will be used more extensively in industries such as natural gas processing and reprocessing plants as well as oil sands plants. The extent of electricity penetration is uncertain, however, and we do not project as rapid growth in electricity demand as does EUPC.

Our projection of the size and distribution of end use energy demand including transportation requirements in the Prairie provinces is summarized in Figure 4-5.

Figure 4-4
End Use Energy Demand, Ontario



Source: Table A4-1, Appendix 4

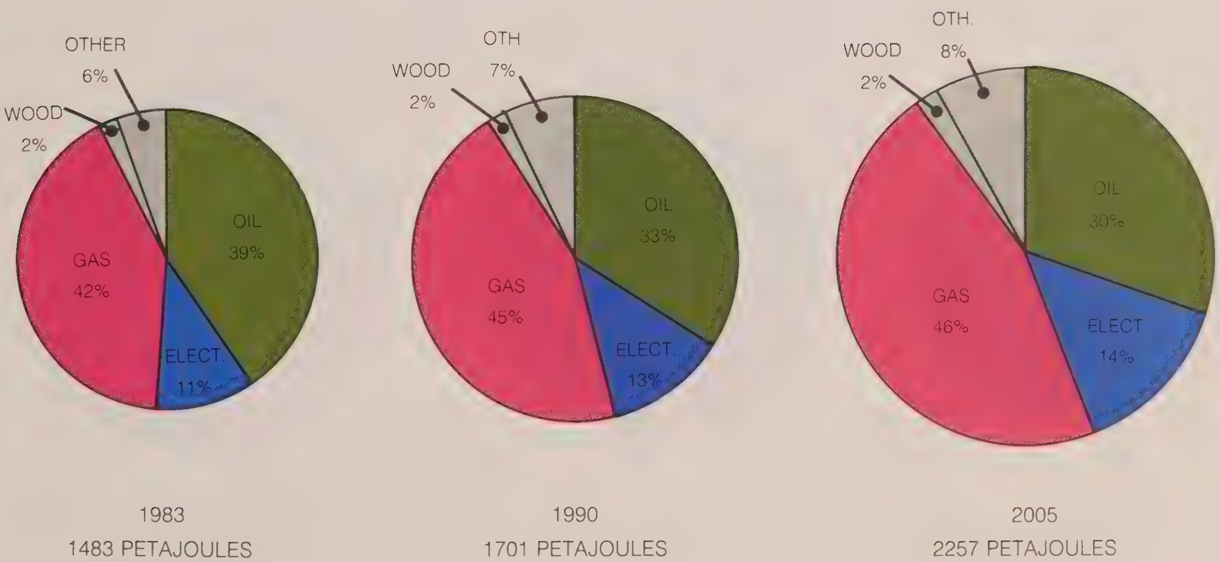
British Columbia, Yukon and Northwest Territories

Energy use in British Columbia is more evenly distributed among the different energy forms than in other regions; gas and electricity each supply some 25 percent of non-transportation end use energy and wood about a third. The Yukon and Northwest Territories, however are heavily dependent on the use of oil, and this situation is not expected to change in the foreseeable future.

Construction of a natural gas pipeline to Vancouver Island is currently under active consideration by the government of British Columbia. Our projections assume that a natural gas pipeline to Vancouver Island will be constructed in 1986 and that, as a consequence, there will be increased use of natural gas mainly at the expense of oil. In the event that this pipeline does not go ahead, the share of end use demand held by natural gas is expected to be about two percentage points lower in 2005 than that shown in Figure 4-6.

Although the British Columbia government has adopted a policy of gradually increasing the price of natural gas to 65 percent of parity with crude oil by 1990, this occurs over a period when real increases in electricity prices are also expected. Hence the price of gas relative to electricity remains fairly constant. Beyond 1990 our assumption of constant real electricity prices implies a gradual improvement in the competitive position of that energy form (Appendix 4, Table A4-3).

Figure 4-5
End Use Energy Demand, Prairies



Source: Table A4-1, Appendix 4

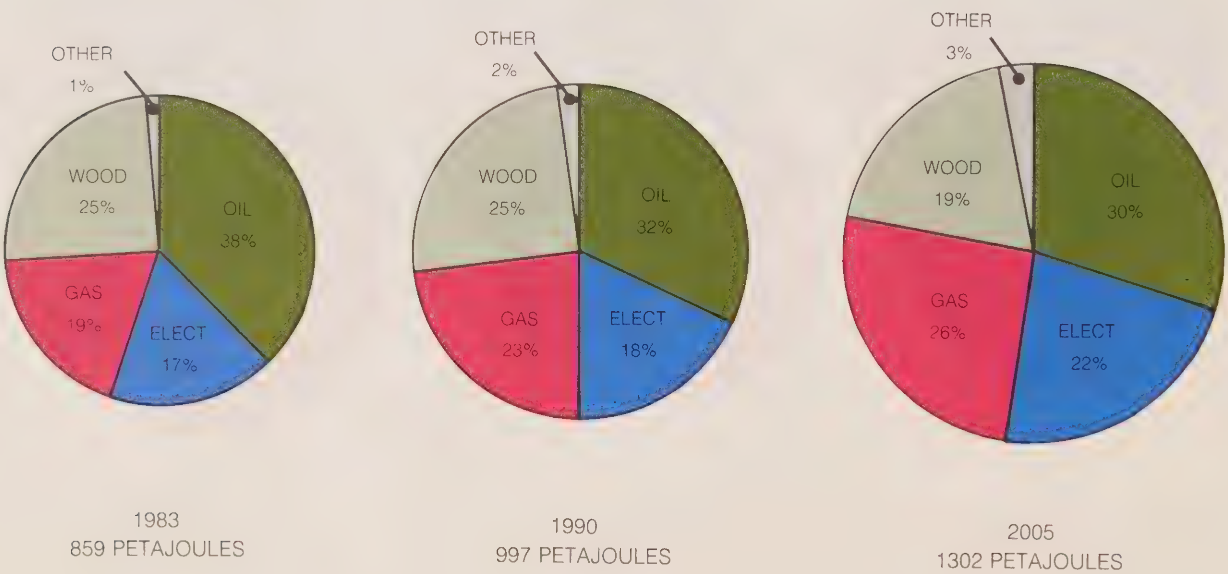
Although we are projecting a continuing increase in the natural gas share of residential markets, partly as a consequence of our assumption about the Vancouver Island pipeline, the increase in gas use will be limited. This is anticipated because gas already has a very large share of the market (about 56 percent of households currently use gas) and because we project considerable energy conservation among households.

In industry there has been a considerable switch from heavy fuel oil to wood wastes and pulping liquor in recent years as a result both of the price increases in oil and natural gas and of the implementation of federal government programs such as the Forest Industry Renewable Energy Program. Wood wastes supply about one-half of all industrial energy used in British Columbia at present.

We are assuming increased electricity penetration in British Columbia industrial markets as a consequence of a shift towards electricity intensive thermo-mechanical pulping processes and of the electricity price discounts to industry of some 30 percent currently being offered by B.C. Hydro.

The natural gas share of industrial markets is more problematical. We have assumed a significant increase, partially as a result of the assumed conversion of local industry on Vancouver Island from heavy fuel oil to gas after 1986. It is far from certain, however, that the combination of rising natural gas prices in British Columbia and the continuing availability of heavy fuel oil from the Pacific Northwest will be con-

Figure 4-6
End Use Energy Demand, B.C., Yukon and N.W.T.



Source: Table A4-1, Appendix 4

ducive to as much use of natural gas in industry as we have assumed.

Figure 4-6 shows projected end use demand by fuel in British Columbia, the Yukon and the Northwest Territories.

4.3 Total End Use Demand by Fuel

Our assessments of the regional outlooks for end use demand of the different forms of energy collectively imply an evolution in the distribution of fuel use in Canada as shown in Table 4-3, and depicted graphically in Figure 4-7.

The sharp decline in the oil share from 59 percent in 1973 to 43 percent in 1983, is projected to continue, dropping to 31 percent of end use energy demand by 2005. Correspondingly, the shares of natural gas and electricity increase significantly. By the end of the projection horizon, oil and natural gas comprise about equal proportions of end use energy in Canada. Oil is used overwhelmingly in transportation, its use as a heating fuel being assumed to be marginal by 2005. We show a small increase in the use of alternative forms of energy resulting from our assumption that the economics related to their use, combined with our assumed price profile for conventional energy, would not be conducive to rapid expansion.

A comparison of our projected fuel shares in 2000 with those of major submittors is shown in Table 4-4. All have assumed movements in the same direction – less oil, more gas and electricity. However, there are significant differences in the extent of the shift away from oil and views of the extent to which expansion will occur in natural gas and electricity.

Our assessment of the sensitivity of the fuel share distribution to alternative assumptions about world oil prices and economic growth (Table 4-5) suggests that:

- refined petroleum product demand is the most sensitive to variations in both variables;
- economic growth affects gas and electricity use about equally;
- the impact of oil prices on electricity demand is very small.

The low impact of oil prices on electricity demand results from offsetting effects. Changes in oil prices affect:

- total energy demand, because they change the average price of energy in general relative to prices of other goods and services;
- the distribution of demand among fuels because they affect the prices of oil and gas relative to electricity.

A rise in oil prices, for example, reduces the demand for total energy, thereby reducing the demand for all

Table 4-3
End Use Energy Demand by Fuel

	Petajoules		Shares-Percent	
	1983	2005	1983	2005
Oil	2773	2750	43	31
Gas	1573	2857	25	31
Electricity	1161	2211	18	24
NGL	125	288	2	3
Coal	233	376	4	4
Steam	57	22	1	—
Renewables	484	664	7	7
Total	6407	9168	100	100

Table 4-4
End Use Energy Shares in 2000[1]

(Percent)

	Oil	Gas	Electricity	Other
Dome-Low	40	28	—	—
Gulf	36	27	23	14
Husky/NOVA	41	29	19	11
Imperial	29	30	24	17
Petro-Canada-Base	32	31	27	10
Shell	35	31	20	14
NEB	31	31	23	15

[1] Most submittors did not project energy demand beyond the year 2000.

fuels including electricity, but at the same time it reduces the relative price of electricity, causing its share of a smaller energy pie to increase.

Our assessment of the likely upper and lower bounds of demand for each energy form in 2000 is shown in Table 4-6. Estimates provided by major submittors are included for comparison.

In comparison to our projection of end use demand in the 1981 NEB Report, oil demand is considerably lower now and throughout the forecast horizon, as shown in Table 4-7.

Lower projected requirements for oil are anticipated in all end use sectors, as a result of off-oil programs, lower economic growth, and additional improvements in the efficiency of oil use in the industrial and transportation sectors. The decline in demand for natural gas is not significantly different from that for total end use demand. The change in the projected use of electricity is minimal, however, reflecting the marketing of surplus electricity by electric utilities which has already occurred, and which is likely to occur in the future.

Table 4-5
Change in Demand from Reference Case in 2005

(Percent)

	Oil	Gas	Electricity	Other	Total
High Growth	17	11	12	6	12
Low Growth	–14	–8	–9	–4	–9
High Price	–12	–7	2	0	–5
Low Price	9	6	–2	0	4

Table 4-6
Total End Use Demand in 2000

(Petajoules)

	Oil	Gas	Electricity	Other[1]	Total
NEB – High	2980	2820	2170	1350	9320
– Reference	2630	2591	1977	1291	8489
– Low	2320	2400	1810	1250	7780
Amoco	—	2530	—	—	—
Dome – Low	3711	2577	—	—	9181
Gulf	3040	2302	1955	1231	8528
Husky/NOVA	3647	2588	1718	1009	8962
Imperial	2207	2296	1811	1246	7560
Petro-Canada – Base	2835	2808	2426	871	8940
Shell	2744	2446	1547	1102	7839

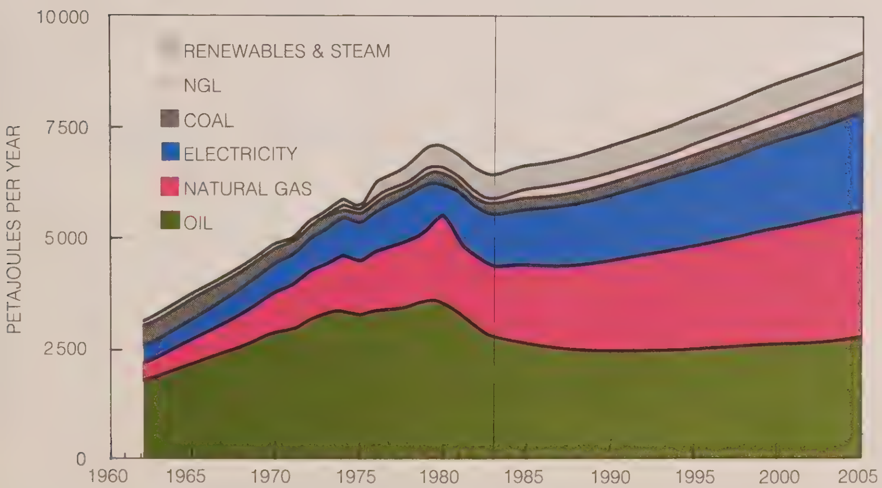
(1) Calculated as residual.

Table 4-7
NEB Projections of End Use Energy Demand by Fuel

(Petajoules)

	1983	1990	2000
Oil			
1981 NEB Report	3531	3407	3880
1984 S/D Update	2773	2482	2630
Percent Difference	−22	−27	−32
Natural Gas			
1981 NEB Report	1863	2450	3135
1984 S/D Update	1573	2012	2591
Percent Difference	−16	−18	−17
Electricity			
1981 NEB Report	1207	1491	2069
1984 S/D Update	1161	1486	1977
Percent Difference	−4	0	−4

Figure 4-7
End Use Energy Demand by Fuel, Canada



Source: Table A4-1, Appendix 4
Table A10-3, Appendix 10

CHAPTER 5

ELECTRICITY

In this chapter we assess the implications of our estimates of electricity demand for future energy production and the resulting mix of fuels to be used to generate electricity. The petajoule end use demand estimates from Chapter 4 are converted to electrical energy units and then adjusted for the utilities' own use and losses and assessments of potential interprovincial sales and exports. We make use of these energy requirements and information from the utilities' stated generation expansion plans to estimate the required plant generating capacities in each province and ultimately the quantities of the several types of fuels that would be required to generate electricity in each year. The quantities of the fuels used to generate electricity are then added to the amounts of the same fuels projected to be used for other purposes, as reported in other chapters of this report, to determine a total demand for all primary energy sources.

In the electricity industry, the units used for energy and power are multiples of kilowatt hours (kW.h) and kilowatts (kW). Other multiples of these units used in this report are gigawatt hours (GW.h), terawatt hours (TW.h), megawatts (MW) and gigawatts (GW).

Table 5-1 shows the terawatt hour equivalents of the demand projections expressed in petajoules in previous chapters. A standard conversion factor of 3.6 megajoules per kilowatt hour is used.

The table also shows estimates of peak loads for each province and region. These have been calculated by assuming a load factor for each province, based generally on historical data. Load factors range typically between 58 and 65 percent.

The provinces have the responsibility for ensuring that there are adequate supplies of electricity available for their needs. A federal crown corporation provides most of the electricity in the territories. Utilities, either provincially owned or regulated and established to supply electricity within provincial boundaries, forecast their customer requirements 10 to 15 years in advance, then arrange for the construction of generation and transmission facilities and for the supply of the fuels and other resources necessary at the time the electricity is to be generated. Industries generating their own electricity similarly plan the construction of their generating plants several years in advance.

Most major Canadian electrical utilities contributed to the Board's current study. In some instances the provincial governments concerned, industries, and associations included information on electricity in their reports. The following sections make extensive use of the information provided by the contributors.

All provinces adjacent to the United States border will have some access to the electricity markets in that country. We have attempted to make estimates

Table 5-1
Electricity Demand in Canada,[1] 1990

	Domestic Energy Demand		
	Petajoules	Terawatt hours	Peak Load Gigawatts
Newfoundland	44	12.2	2.26
Prince Edward Island	3	.7	.15
Nova Scotia	34	9.4	1.67
New Brunswick	45	12.5	2.53
Total Atlantic	**125**	**34.8**	**6.61**
Quebec	573	159.2	29.41
Ontario	492	136.6	24.38
Manitoba	62	17.2	3.37
Saskatchewan	50	14.0	2.69
Alberta	131	36.5	6.49
Total Prairies	**243**	**67.6**	**12.55**
British Columbia	199	55.3	9.42
Yukon	2	.5	.10
Northwest Territories	2	.6	.13
Total B.C. and North	**203**	**56.5**	**9.65**
Total Canada	**1637**	**454.7**	**82.60**

[1] Excludes export sales.

of possible exports and in doing so, assumed that all surpluses of hydro and nuclear-generated energy not sold to adjacent provinces would be exported up to the capacity limits of existing and committed international interconnections. In some instances, there will be export markets for electricity produced in coal-fired thermal plants.

No account has been taken of exports from surplus electricity that could be generated in oil – or gas-rifed thermal plants except for some firm exports from New Brunswick which are expected to end in 1986. Such exports will likely be small. We have also assumed a small component of dedicated exports (Lepreau II in New Brunswick) and advancement of generation (Limestone Generating Station in Manitoba) based on published reports to account for potential exports which are currently contemplated by utilities. Except for these exports the forecast does not include any additional schemes involving advancing or constructing generation facilities explicitly for export purposes.

It is not the purpose of this exercise to assess either the desirability or feasibility of exporting electricity. Any such exports are subject to Board approval.

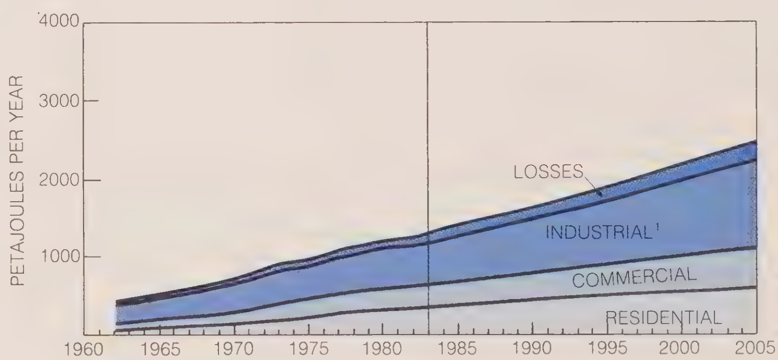
5.1 Total Electricity Demand

Electricity demand growth has slowed considerably in recent years from the very high and stable rates of increase which had characterized growth in electricity use during the 1960s and early 1970s. Anticipating continued growth near these rates, utilities constructed facilities to accommodate them. The result is that existing generating capacity is substantially in excess of current requirements and those expected over the next few years. As a result future expansion plans have been scaled down and as noted in Chapter 4 some utilities have implemented incentive pricing schemes to encourage expanded use of electricity. In our demand projections we have attempted to take account of the impact of these incentive schemes. We have also noted that intense competition exists between natural gas and electricity, particularly in central Canada and that the outcome of the battle for markets is far from clear.

Our estimate of growth in electricity demand reflects our view that utilities will succeed in their attempts to dispose of existing surplus capacity.. Accordingly we project growth in electricity demand at an average annual rate of 3.5 percent for the rest of the decade slowing to an average annual rate of 2.6 percent between 1990 and 2005. Although slow relative to past growth in electricity requirements these rates of growth are significantly higher than those we have projected for non-transportation end use energy demand, 1.7 and 2.0 percent in the periods 1983-1990 and 1990-2005 respectively.

Our Reference Case projection of growth in end use electricity demand is compared to projections prepared by electric utilities and other submittors in

Figure 5-1
Total Electricity Demand, Canada



Source: Table A5-2, Appendix 5
Table A10-3, Appendix 10

[1]Includes minor transportation uses

Table 5-2. In most instances, our provincial growth rates are similar to those of electric utilities (Refer to Appendix 5 for a more detailed comparison).

The uncertainty in the prospects for electricity is reflected in our estimate of the plausible range for requirements (Table 5-3). There is a 13 percent difference between our low and high estimates for 1990 and a 22 percent difference in levels by 2005.

5.2 Generating Capacity and Energy Production by Region

Electricity demand by customers varies with the time of day and season. Canadian utilities are winter peaking and the annual peak demand usually occurs in December or January. Electricity producers are required to have sufficient generating capacity available to meet this peak demand.

Sound engineering practice also requires the carrying of reserve generating capacity to allow for possible equipment breakdowns and maintenance and to provide for reliable and continuous service to customers. Some utilities may require a slightly larger reserve margin than others depending on individual operating conditions.

Each generating unit will have an amount of energy associated with it that

Table 5-2
Projections of Rate of Growth in Electricity Demand[1]

1983-2000
Unless otherwise indicated

(Percent per year)

	Canada	Nfld.	N.S.	P.E.I.	N.B.	Quebec	Ontario	Manitoba	Sask.	Alberta	B.C.	Yukon & N.W.T.
NEB 1983-2005	3.0	4.0	4.1	3.7	4.0	3.0	2.5	1.9	3.1	3.4	3.2[2]	—
NEB 1983-2000	3.2	4.4	4.4	4.2	4.4	3.3	2.7	2.1	3.2	3.5	3.3[2]	—
Provincial Utilities	—	—	—	1.8	3.2[3]	2.3[3]	2.6	2.9	—	4.4	3.4	2.9
Provincial Governments	—	4.6	2.5	—	3.1[3]	1.3-3.5[3]	2.4	—	2.9	—	—	—
GIC	—	—	—	—	—	2.2	—	—	—	—	—	—
CPA	—	—	—	—	—	—	2.5	—	—	—	2.2[2][3]	—
Gulf	3.1	4.0	4.0	4.0	4.0	2.7	3.3	2.6	3.1	3.9	2.6[2]	—
Husky/NOVA	2.5	—	—	—	—	—	1.9	—	3.5	2.2	3.1[2]	—
Imperial	2.5	2.7	2.7	2.7	2.7	1.6	2.6	—	—	5.0	2.5[2]	—
Petro-Canada	4.4	6.3	6.3	6.3	6.3	2.4	4.5	4.5	8.6	5.8	5.4[2]	—
Shell	1.7	2.5	2.0	2.0	2.0	1.6	1.6	0.9	1.6	2.8	1.7[2]	
TCPL	—	—	—	—	—	2.2	1.9	2.3	1.8	—	—	—

(1) Excludes losses.
(2) Includes Yukon, N.W.T.
(3) Years differ from those indicated.

Table 5-3
Range in Total Electricity Demand

	1983		1990		2005	
	PJ[1]	TW.h[2]	PJ	TW.h	PJ	TW.h
High	1282	356	1740	478	2704	730
Reference Case	1282	356	1637	455	2431	675
Low	1282	356	1545	429	2222	617

(1) PJ – petajoules
(2) TW.h – terawatt hours

it could reasonably be expected to produce each year. There are several different types of generating units, each designed for a particular type of service corresponding to the amount of time the unit may be required to operate. For instance, a base load nuclear unit may operate 85 percent of the time, producing considerable energy, while an oil-fired peaking unit of the same capacity may operate only 5 percent of the time, producing little energy.

If customer requirements are not as high as forecast, excess energy may be available. The quantity of energy produced for export will depend on market conditions, the capacities of interconnections to the United States utilities, fuel costs and reservoir levels in Canada. During the next decade the continuing use of oil for electricity generation in the United States and the availability of more economic surpluses from hydroelectric and coal fired generation in Canada is likely to result in considerable opportunities for oil displacement sales. In the 1990s United States utilities may also need firm capacity which could provide export opportunities to Canadian utilities.

Provincial Projections

In each province, the plans for future generation expansion are based on the use of different primary resources. In Alberta and Saskatchewan, for example, expansion plans are largely based on the development of local coal deposits and in Quebec, Manitoba and British Columbia they are based on hydro resources.

Because means of generation differ and planning is done at the provincial level we first outline the prospects for the evolution of capacity and production to meet energy requirements by province. Account is taken of potential interprovincial transfers and of exports. We then summarize the implications for the evolution of capacity and production in Canada.

The current distribution of installed capacity and energy generation across provinces is summarized in Table 5-4.

Tables 5-5 through 5-16 provide our projections of capacity and production data by province and territory. More detailed information can be found in Tables A5-4 and A5-5 of Appendix 5. It should be noted that the Remaining Capacity shown in the provincial summary tables includes the required reserve capacity.

Newfoundland and Labrador

While the province of Newfoundland and Labrador has a large hydroelectric

Table 5-4
Installed Capacity and Generation by Province and Territory 1983

	Capacity		Energy	
	Percent	Megawatts	Percent	Gigawatt hours
Newfoundland	8.8	7 445	10.1	40 123
Prince Edward Island	0.1	110	—	11
Nova Scotia	2.5	2 083	1.2	4 890
New Brunswick	4.0	3 371	2.9	11 540
Quebec	25.8	21 829	27.9	110 607
Ontario	29.9	25 222	29.8	117 989
Manitoba	4.8	4 061	5.6	22 110
Saskatchewan	3.0	2 567	2.5	9 946
Alberta	7.5	6 298	7.3	28 757
British Columbia	13.2	11 182	12.5	49 315
Yukon	0.1	126	0.1	243
Northwest Territories	0.2	190	0.1	494
Total	100	84 484	100	396 025

Source: Tables A5-4 and A5-5, Appendix 5

Table 5-5
Generation of Electricity in Newfoundland and Labrador

	1983	1990	2005
Generating Capacity (MW)	7 445	7 805	9 541
Domestic Peak Demand	1 614	2 261	3 869
System Peak Demand	6 839	7 476	9 054
Remaining Capacity	606	329	487
Percent of Domestic Peak(1)	N/A	14.6	12.6
Energy Production (GW.h)	40 123	47 382	56 220
Hydro	39 516	44 508	55 866
Coal	—	—	—
Nuclear	—	—	—
Other	607	2 874	354
Domestic Consumption (GW.h)	8 884	12 186	20 721
Net Interprov. Transfers (out)	31 239	35 196	35 499
Net Exports	—	—	—

(1) Remaining Capacity is expressed as a percentage of domestic peak for Newfoundland and Labrador, rather than of system peak. For 1983, the percentage of domestic peak was not calculated because the Island and Labrador systems are not interconnected.

generating capacity in Labrador most of this is under long term contract to supply Quebec. At present the Newfoundland and Labrador power systems are not interconnected. The province currently depends heavily on oil-fired generating capacity to supply Island use. In the Reference Case we assumed that Labrador hydro capacity would be available to the Island by submarine cable in the early 1990s. From then on a large percentage of the energy used in the province will be from hydro, displacing most of the oil-fired generation.

Prince Edward Island

Although Prince Edward Island has adequate oil-fired generating capacity to satisfy its own needs it has been obtaining most of its energy from New Brunswick via a submarine cable interconnection for economic reasons.

Table 5-6
Generation of Electricity in Prince Edward Island

	1983	1990	2005
Generating Capacity (MW)	110	155	245
Domestic Peak Demand	115	152	275
System Peak Demand	115	152	275
Remaining Capacity(1)	22	45	44
Percent of System Peak	19.1	29.6	16.0
Energy Production (GW.h)	11	100	900
Hydro	—	—	—
Coal	—	—	881
Nuclear	—	—	—
Other	11	100	19
Domestic Consumption (GW.h)	555	716	1250
Net Interprov. Transfers (in)	544	616	350
Net Exports	—	—	—

(1) Takes into account capacity purchased from New Brunswick of 27 megawatts in 1983, 42 megawatts in 1990, and 74 megawatts in 2005.

While the Reference Case has assumed the installation of a 50 megawatt coal-fired unit in the early 1990s it is recognized that Prince Edward Island may, as an alternative, be able to arrange additional capacity purchases from neighbouring provinces. Future sources of energy may, therefore, be from either coal or purchases from other provinces.

Nova Scotia

Nova Scotia's generating capacity is currently a mix of 35 percent coal-fired, 48 percent oil-fired, and 17 percent hydroelectric. While the 20 megawatt experimental Annapolis Tidal plant was added to the province's generating capacity in 1984, for the purposes of this study it was assumed that a major tidal project would not be in service before 2005. We also assumed that additional coal-fired generation would

Table 5-7
Generation of Electricity in Nova Scotia

	1983	1990	2005
Generating Capacity (MW)	2 083	2 226	4 003
Domestic Peak Demand	1 258	1 667	2 909
System Peak Demand	1 258	1 667	2 909
Remaining Capacity	825	559	1 094
Percent of System Peak	65.6	33.5	37.6
Energy Production (GW.h)	4 890	9 229	16 237
Hydro	997	1 033	1 033
Coal	2 330	5 715	14 602
Nuclear	—	—	—
Other	1 563	2 481	602
Domestic Consumption (GW.h)	5 565	9 359	16 367
Net Interprov. Transfers (in)	675	130	130
Net Exports	—	—	—

be employed in the early 1990s. The province is expected to be heavily dependent on coal produced energy throughout the study period using coal mined within the province. Small amounts of natural gas may be used for generation after 1989.

Nova Scotia is interconnected with New Brunswick and may, at times, purchase energy from that province.

New Brunswick

New Brunswick currently has a mix of 27 percent hydroelectric, 46 percent oil-fuelled, 8 percent coal-fired and 19 percent nuclear capacity. We have assumed that an additional 630 MW nuclear plant will be installed in the early 1990s for export and major existing oil-fired facilities will be converted to coal. While in the 1990s the major source of the province's electrical energy will be nuclear plants, and although much of the nuclear energy may be exported, there will still be a substantial amount generated from coal and purchases from Quebec will continue to be significant. Some natural gas may be used for generation after 1989.

New Brunswick is interconnected with Quebec, Nova Scotia, Prince Edward Island and the New England States and purchases energy from Hydro-Québec while selling electricity to Prince Edward Island, Nova Scotia and New England.

Quebec

Quebec's generating capacity is 93 percent hydroelectric, 2.5 percent nu-

Table 5-8
Generation of Electricity in New Brunswick

	1983	1990	2005
Generating Capacity (MW)	3 371	3 371	5 941
Domestic Peak Demand	1 685	2 534	4 267
System Peak Demand	2 075	2 906	4 971
Remaining Capacity	1 296	465	970
Percent of System Peak	62.5	16.0	19.5
Energy Production (GW.h)	11 540	15 978	27 071
Hydro	3 110	2 777	2 647
Coal	1 954	5 480	5 392
Nuclear	4 759	4 415	17 660
Other	1 717	3 306	1 372
Domestic Consumption (GW.h)	8 623	12 541	21 484
Net Interprov. Transfers (in)	2 768	2 836	458
Net Exports	5 685	6 273	6 045

Table 5-9
Generation of Electricity in Quebec

	1983	1990	2005
Generating Capacity (MW)	21 829	28 925	44 927
Domestic Peak Demand	22 214	29 413	43 616
System Peak Demand	22 309	29 469	43 616
Remaining Capacity[1]	4 745	4 671	6 496
Percent of System Peak	21.3	15.9	14.9
Energy Production (GW.h)	110 607	141 443	199 151
Hydro	110 322	136 603	193 296
Coal	—	—	—
Nuclear	—	4 464	4 464
Other	285	376	1 391
Domestic Consumption (GW.h)	122 338	159 243	233 895
Net Interprov. Transfers (in)	21 958	28 544	34 744
Net Exports	10 227	10 744	—

(1) Takes into account capacity purchased from Churchill Falls of 5225 MW in 1983, 5215 MW in 1990, and 5185 MW in 2005.

clear and the remainder oil-fuelled. The Churchill Falls purchase from Labrador forms a significant portion of the available energy. We assumed that Quebec will require additional peaking and base load capacity in the 1990s. Apart from the energy produced in the province's only nuclear plant, electricity will be supplied almost entirely from hydro sources in Quebec and Labrador.

Quebec has interconnections with Ontario, New Brunswick, Newfoundland (Churchill Falls), the State of New York and the New England States.

Although there have been suggestions that Hydro-Québec will advance generation to make additional exports our present forecast does not assume that this will take place.

As Hydro-Québec has large reservoir storage it is able to regulate its use of water for hydroelectric production, approximating average river conditions, to supply its own firm energy requirements. Over the long term energy production matches requirements with no excess energy for export purposes. Accordingly we have shown exports falling off to zero by 2005.

Ontario

Ontario's mix of generating capacity is currently 38 percent coal, 29 percent hydroelectric, 27 percent nuclear, 3.5 percent gas and 2.5 percent oil. While some small hydroelectric plants may be added, we have assumed that the province will continue to construct nuclear generating plants as new capacity is required.

By the end of the study period, 68 percent of Ontario's electrical energy will be from nuclear sources, 22 per-

Table 5-10
Generation of Electricity in Ontario

	1983	1990	2005
Generating Capacity (MW)	25 222	29 360	40 835
Domestic Peak Demand	18 807	24 385	33 972
System Peak Demand	19 462	24 785	33 972
Remaining Capacity	5 760	4 575	6 863
Percent of System Peak	29.6	18.5	20.2
Energy Production (GW.h)	117 989	145 187	195 649
Hydro	40 360	37 968	43 084
Coal	36 105	19 268	19 992
Nuclear	39 472	85 624	129 821
Other	2 052	2 327	2 752
Domestic Consumption (GW.h)	112 428	136 640	191 025
Net Interprov. Transfers (in)	6 277	3 446	454
Net Exports	11 838	11 993	5 078

Table 5-11
Generation of Electricity in Manitoba

	1983	1990	2005
Generating Capacity (MW)	4 061	4 198	5 368
Domestic Peak Demand	2 767	3 365	4 162
System Peak Demand	2 767	3 365	4 662
Remaining Capacity	1 668	1 133	706
Percent of System Peak	60.2	33.7	15.1
Energy Production (GW.h)	22 110	20 718	27 194
Hydro	21 892	20 630	27 100
Coal	67	—	—
Nuclear	—	—	—
Other	151	88	94
Domestic Consumption (GW.h)	14 775	17 158	21 242
Net Interprov. Transfers (out)	1 342	850	850
Net Exports	5 993	2 710	5 102

cent from hydro and 10 percent from coal and other sources.

Ontario is interconnected with both Quebec and Manitoba and with the states of New York and Michigan. Through the United States interconnections Ontario Hydro has access to markets in other states.

Manitoba

Manitoba's generating capacity is 81 percent hydroelectric, 17 percent coal-fired and 2 percent other types. We have assumed that the new Limestone hydro plant capacity will be available early in the 1990s and that 500 MW of the new capacity would be devoted to export. We have not included possible additional sales to the Western Area Power Administration or to utilities in the State of Wisconsin which the province is still negotiating.

Currently 99 percent of the electrical energy used in the province is from hydro plants. This situation is expected to continue throughout the study period.

Manitoba has interconnections with Ontario, Saskatchewan and North Dakota and Minnesota in the United States.

Saskatchewan

Saskatchewan's generating capacity mix is 62 percent coal, 23 percent hydroelectric, 14 percent gas, and one percent other. The Reference Case assumes additional coal-fired generation will be installed. While 75 percent of the province's electrical energy was

Table 5-12
Generation of Electricity in Saskatchewan

	1983	1990	2005
Generating Capacity (MW)	2 567	3 083	4 553
Domestic Peak Demand	2 048	2 689	3 851
System Peak Demand	2 122	2 689	3 851
Remaining Capacity	445	394	702
Percent of System Peak	21.0	14.7	18.2
Energy Production (GW.h)	9 946	13 514	19 721
Hydro	2 264	3 832	6 167
Coal	7 299	9 243	12 918
Nuclear	—	—	—
Other	383	439	636
Domestic Consumption (GW.h)	10 352	13 988	20 195
Net Interprov. Transfers (in)	487	474	474
Net Exports	81	—	—

generated from coal in 1983, hydroelectricity is expected to increase in importance by the year 2005.

Saskatchewan has interconnections with Manitoba and with North Dakota in the United States.

Alberta

Alberta's generating capacity is 60 percent coal-fired, 25 percent gas-fired, 13 percent hydroelectric and 2 percent oil-fired. The Reference Case assumes that new coal-fired facilities will be developed and a new hydro plant will be available in the early 1990s. The province relied on coal for 80 percent of its electrical generation in 1983. By the year 2005, hydro is expected to contribute 23 percent of the province's electrical energy, the balance continuing from coal.

Table 5-13
Generation of Electricity in Alberta

	1983	1990	2005
Generating Capacity (MW)	6 298	7 919	12 556
Domestic Peak Demand	4 691	6 490	10 619
System Peak Demand	4 691	6 990	10 619
Remaining Capacity	1 607	929	1 937
Percent of System Peak	34.3	13.3	18.2
Energy Production (GW.h)	28 757	41 657	63 447
Hydro	1 480	1 636	14 386
Coal	20 791	36 179	46 071
Nuclear	—	—	—
Other	6 486	3 842	2 990
Domestic Consumption (GW.h)	28 899	36 457	59 147
Net Interprov. Transfers (in)	142	100	100
Net Exports	0	5 300	4 400

Alberta is interconnected with British Columbia. We have assumed the sale of 500 MW of firm power between 1986 and 1990 to the United States via British Columbia. A possible Fording coal development dedicated to export has not been included in this study.

British Columbia

British Columbia's generating capacity mix is 84 percent hydro, 13 percent gas, and 3 percent oil-fired and other types. In the Reference Case, we have anticipated the construction of a new hydro plant to be in service in the early 1990s. Hydroelectricity accounted for 96 percent of the province's generation in 1983 and is expected to continue to play a similar role up to 2005.

British Columbia has interconnections with Alberta, the Northwestern

Table 5-14
Generation of Electricity in British Columbia

	1983	1990	2005
Generating Capacity (MW)	11 182	13 012	18 910
Domestic Peak Demand	7 766	9 419	15 227
System Peak Demand	7 773	11 419	15 234
Remaining Capacity	3 409	2 093	3 676
Percent of System Peak	43.9	18.3	24.1
Energy Production (GW.h)	49 315	63 988	91 683
Hydro	47 436	61 964	89 301
Coal	—	—	—
Nuclear	—	—	—
Other	1 879	2 024	2 382
Domestic Consumption (GW.h)	46 600	55 318	88 203
Net Interprov. Transfers (out	142	100	100
Net Exports	2 573	8 570	3 380

United States and a minor link with Alaska. We have assumed the sale of 300 MW (320 GW.h per year) under the terms of the Skagit Valley treaty starting in 1985 in addition to current sales.

Yukon

In the Yukon, 62 percent of the generating capacity is hydroelectric and 38 percent is oil-fuelled. The Reference Case anticipates the installation of additional internal combustion capacity in the early 1990s. Approximately 90 percent of energy generation was from hydro in 1983.

Hydro and diesel generation will continue to supply the territory's energy throughout the study period. It should be noted that domestic consumption for 1983 was 29 percent lower than in the previous year due to curtailment of mining activity. We have assumed this activity will recover in the near future.

While there has been some discussion of a possible interconnection between the Yukon and the Alaska Panhandle, such an interconnection has not been assumed in this forecast.

Table 5-15
Generation of Electricity in Yukon

	1983	1990	2005
Generating Capacity (MW)	126	126	204
Domestic Peak Demand	85	97	154
System Peak Demand	85	97	154
Remaining Capacity	41	29	50
Percent of System Peak	48.2	29.9	32.5
Energy Production (GW.h)	243	508	810
Hydro	221	388	688
Coal	—	—	—
Nuclear	—	—	—
Other	22	120	122
Domestic Consumption (GW.h)	243	508	810
Net Interprov. Transfers	—	—	—
Net Exports	—	—	—

Northwest Territories

The Northwest Territories generating capacity is made up of 77 percent oil-fuelled internal combustion units and 23 percent hydro. The Reference Case assumes that a 10 megawatt hydro plant will be constructed in the late 1980s. Electricity generation in 1983 was 56 percent hydro, the balance came from diesel units.

By the year 2005 it is projected that 57 percent of the energy will be from diesel and the balance from hydro.

Table 5-16
Generation of Electricity in Northwest Territories

	1983	1990	2005
Generating Capacity (MW)	190	207	256
Domestic Peak Demand	96	130	203
System Peak Demand	96	130	203
Remaining Capacity	94	77	53
Percent of System Peak	97.9	59.2	26.1
Energy Production (GW.h)	494	621	990
Hydro	279	325	429
Coal	—	—	—
Nuclear	—	—	—
Other	215	296	561
Domestic Consumption (GW.h)	494	621	990
Net Interprov. Transfers	—	—	—
Net Exports	—	—	—

While there is a possibility of an interconnection with Alberta if that province builds a hydroelectric plant on the Slave River, such an interconnection has not been included in this study.

5.3 Implications for National Capacity and Production

The implications of our provincial analysis for the evolution of national generating capacity and electricity production are shown in Table 5-17. Capacity grows at an average annual rate of 2.5 percent in the years to 1990, somewhat slower than the projected rate of increase in demand (3.5 percent). Between 1990 and 2005, growth of capacity (2.6 percent per year) is equal to the rate of growth in demand.

Total capacity is expected to grow from 84.5 GW in 1983 to 147.1 GW in the year 2005. This growth will be necessary to meet anticipated levels of peak demand for electricity.

Over the country as a whole, hydroelectric generating capacity is expected to remain at approximately 60 percent of total generating capacity through to 2005. Nuclear generating capacity is forecast to increase in importance with its share growing from 9 percent in 1983 to 16 percent in 2005. Coal-fired generating capacity may decrease slightly from 20 percent of total generating capacity in 1983 to 18 percent in the year 2005. Oil and gas-fired generating capacity will decrease from 12 percent of total capacity in 1983 to 8 percent in 2005.

While there will be some increase in generating capacity using non-conventional processes, it is not anticipated that these sources will account for an appreciable portion of overall generating capacity during the period under review.

Industrial generating capacity of various types accounted for approximately 6200 megawatts or 7.5 percent of total generating capacity in 1983. Such generation is expected to amount to approximately 7700 megawatts or five percent of total capacity in the year 2005.

Figure 5-2 illustrates the historical growth in total generating capacity for all of Canada from 1960 through to 1983 and similar forecast quantities to the year 2005. The existing and committed capacity as of 1983 and the additional capacity required to meet the Reference Case demand projection have been indicated on the same graph. Generating capacity tables by province or territory are included in Appendix 5, Table A 5-4.

Figure 5-2 also shows the sum of the non-coincident peak loads of all major utilities, minor utilities and industrial generation, including firm export sales and the required reserve capacity for every fifth year from 1960 to 2005. From this figure it is evident that generating capacity is currently significantly larger relative to peak load than it has been in the past. This reflects the recent large increase in generating capacity which was constructed to meet demands which have not, in fact, materialized. Given the currently projected growth rate of demand, there will be surplus capacity to the late 1980s which will allow for increased export opportunities.

The implications of our provincial projections for national distribution of electricity production across fuels are shown in Table 5-18 and Figure 5-3.

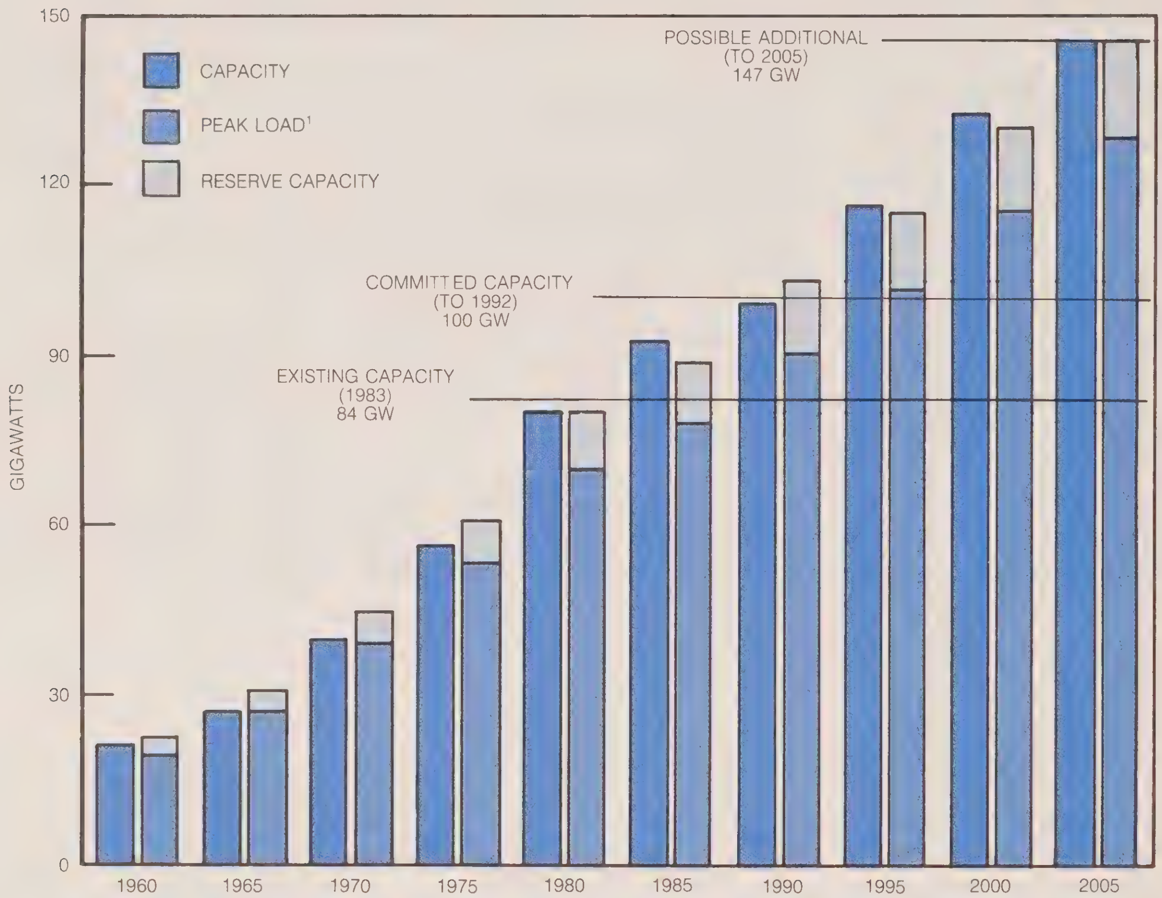
On a Canada wide basis, the share of hydro in total energy production is projected to continue to decline. We also project a decline in the share of fossil

Table 5-17
Generation of Electricity in Canada

	1983	1990	2005
Generating Capacity (GW)	84.5	100.4	147.1
Domestic Peak Demand[(1)]	63.1	82.6	123.1
System Peak Demand[(1)]	69.6	91.1	129.5
Remaining Capacity	14.9	9.3	17.6
Percent of System Peak	21.4	10.2	13.6
Energy Production (TW.h)	396.0	500.3	699.3
Hydro	267.9	311.7	434.0
Coal	68.5	75.9	99.9
Nuclear	44.2	94.5	151.9
Other	15.4	18.2	13.5
Domestic Consumption (TW.h)	359.7	454.7	675.3
Net Exports	36.3	45.6	24.0

(1) These numbers are the sum of provincial peak demands, which are not necessarily coincident peaks. To this extent, remaining capacity and percent of system peak values may be understated on a national level

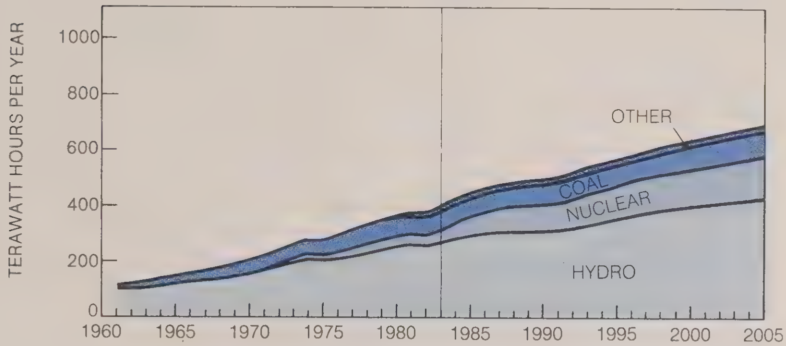
Figure 5-2
Generating Capacity, Peak Load and Reserve Capacity, Canada



Source: Table A5-4, Appendix 5
and Statistics Canada Bulletin 57-204

[1]Including firm exports. National peak load must be interpreted with caution, it is a sum of provincial system peak loads which may not coincide.

Figure 5-3
Electricity Production by Fuel Type, Canada



Source: NEB Reports — Canadian Electric Utilities, Analysis of Generation and Trends 1971 to 1982 and Table A5-5, Appendix 5

Table 5-18
Electricity Production by Fuel Type – Total Canada

	1983		1990		2005	
	Terawatt hours	Percent	Terawatt hours	Percent	Terawatt hours	Percent
Coal	68.5	17	75.9	15	99.9	14
Hydro	267.9	68	311.7	62	434.0	62
Nuclear	44.2	11	94.5	19	151.9	22
Oil and Natural Gas	13.2	3	15.2	3	9.5	1
Other	2.2	1	3.0	1	4.0	1
Total	396.0	100	500.3	100	699.3	100

Source: Table A5-5, Appendix 5

fuels (coal, oil and natural gas). In contrast, the share of nuclear is projected to double over the projection period.

Electricity Exports

Significant transfers of electricity between provinces are made but the magnitude of such movements is limited by economics; electrical transmission is a relatively expensive way to move energy over the long distances separating many of the population centres in Canada. It is frequently found that the United States provides more economically accessible markets for Canadian surpluses.

The forecast of total electricity exports by province for selected years is shown in Table 5-19. In the remaining years of this decade the major exporters are expected to be Quebec and Ontario, exports will also take place from New Brunswick, Manitoba, Saskatchewan, Alberta and British Columbia. The exports from Alberta are anticipated to start in the mid-1980s.

The various fuels used to produce this energy for export are shown, for all of Canada, in Figure 5-4.

Potential exports are expected to increase to approximately 60 terawatt hours per year in the late 1980s declining thereafter to about 24 terawatt hours per year in 2005. Between 3 and 13 percent of the electricity produced in Canada is expected to be exported annually throughout the study period (Figure 5-5). If other export possibilities, still in the preliminary discussion stages, come to pass, exports could be higher.

5.4 Primary Fuels Used to Generate Electricity

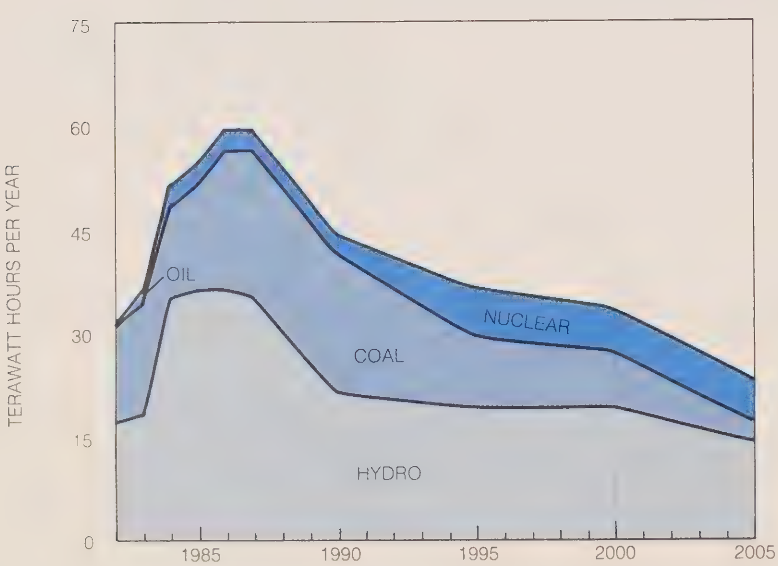
To determine the primary energy consumed in the production of electricity we use plant specific conversion factors for electricity produced at fossil fuel fired plants. For hydro and nuclear

Table 5-19
Forecast of Total Electricity Exports

	1983 Terawatt hours	1990 Terawatt hours	2005 Terawatt hours
New Brunswick	5.7	6.3	6.0
Quebec	10.2	10.7	—
Ontario	11.8	12.0	5.1
Manitoba	6.0	2.7	5.1
Saskatchewan	0.1	—	—
Alberta	—	5.3	4.4
British Columbia	2.6	8.6	3.4
Canada Total	**36.4**	**45.6**	**24.0**

Source: Table A5-7, Appendix 5.

Figure 5-4
Electricity Exports By Fuel Type
Canada



Source: Table A5-8, Appendix 5

generating plants, a factor of 10.5 megajoules per kilowatt hour is used. Use of this factor is later discussed in Chapter 10.

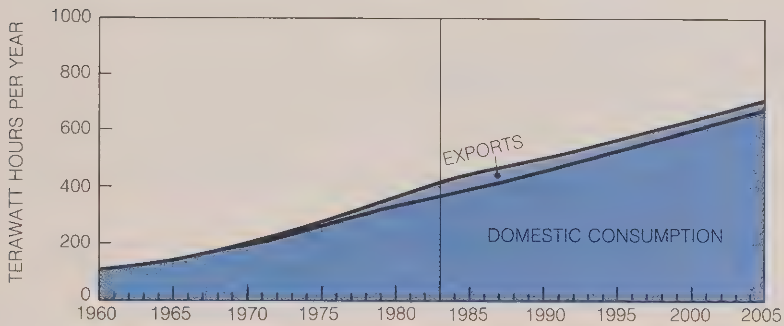
The amounts of the various source fuels used for the generation of electricity, in sample years expressed in petajoules, are shown in Appendix 5, Table A5-6. Appendix 10, Table A10-3 shows the petajoules quantities for all energy forms at the source including those used to generate electricity. It can be seen from Table A5-6 that the total primary energy demand associated with the production of electricity rises from approximately 4 200 petajoules in 1983 to 7 500 petajoules in the year 2005. In that year the production of electricity will consume 51 percent of the 14 600 petajoules of total primary energy. The source demand of 7 500 petajoules in 2005 represents an overall increase of 78 percent over the 1983 value of 4 200 petajoules.

Out of the 7 500 petajoules to be consumed to produce electricity in 2005 some 4 580 petajoules or 62 percent are accounted for by hydroelectricity on the basis of the conversion factor referred to above. Expressed in another manner, were it not for the abundant supply of hydro-generated electricity in Canada, in the year 2005 Canadians would have to consume an additional 4 580 petajoules of fossil or nuclear energy in order to enjoy the same level of electricity use. This would be equivalent to an increase of approximately 45 percent in the national demand for such fuels. The flow diagram in Figure 10-1 in Chapter 10 illustrates the substantial demand for primary fuels needed to produce electricity.

Hydroelectricity

Approximately 270 000 gigawatt hours (equivalent to 2830 petajoules of primary energy) of electricity (nearly 68 percent of total production) was from hydro plants in 1983. Production from

Figure 5-5
Demand for Electric Energy
Canada



Source: Table A5-5, Appendix 5
and Statistics Canada Bulletin 57-204

this source is anticipated to increase to over 430 000 gigawatt hours (equivalent to 4580 petajoules) or 61 percent of total production in 2005.

Hydroelectric production will be important in all of the provinces with the exception of Prince Edward Island during the period under review. Many of the provinces reported the existence of hydro sites that could be developed in the future.

Coal

In 1983 nearly 750 petajoules of coal were used to generate 17 percent of the electricity produced in Canada. The amount of coal used to generate electricity will increase to approximately 1 150 petajoules in the year 2005.

The use of coal for electricity generation will continue to be important in Nova Scotia, New Brunswick, Ontario, Saskatchewan and Alberta. The province of Ontario is expected to continue to use large quantities of bituminous coal imported from the United States although this will account for a decreasing percentage of production from year to year. Western coal will be used in the provinces of Alberta, Saskatchewan, and Ontario, and may be used in New Brunswick if it is decided to convert the Coleson Cove plant from oil to coal. Ample supplies of coal will be available to satisfy the needs for thermal generation throughout the study period.

Nuclear

The amount of nuclear energy used to generate electricity at nuclear plants is expected to grow from nearly 470 petajoules in 1983 to approximately 1 600 petajoules in the year 2005.

We assumed in the Reference Case that nuclear generation would occur only in Ontario, Quebec and New Brunswick during the forecast period. The supply of uranium in Canada will be more than adequate to satisfy the requirements in nuclear plants in the study period.

Oil

An examination of the trends in the use of the various fuels used to produce electricity reveals that electric utilities have taken steps to decrease the amount of oil used for this purpose. In 1983 approximately 55 petajoules were used to generate 1.5 percent of total electricity production. In the Reference Case oil used for electricity generation is expected to drop to some 49 petajoules or 0.6 percent of electricity production in the year 2005. One of the major continuing uses of oil will be to operate diesel plants in remote areas.

Imported heavy fuel oil is expected to account for decreasing shares of production in Newfoundland, New Brunswick and Nova Scotia as other sources become available over the period under review.

Natural Gas

About 64 petajoules of natural gas were used for 1.5 percent of total electricity production in 1983. The use of natural gas is expected to decrease to about 33 petajoules or less than one percent of total electricity production in 2005.

Other

Electricity generated by other fuels amounts to less than one percent of total annual generation throughout the period under review. Other fuels include hog fuel, pulping liquor, coke oven and blast furnace gas, waste heat from metallurgical coal and other biomass and fossil fuel by-product sources, wind and solar power.

For Canada as a whole, electricity energy demand is expected to increase by approximately 88 percent and peak demand by approximately 95 percent over the 22 year period, 1983 to 2005. Coal, hydro and uranium are expected to play increasingly important roles in terms of the amount of electrical energy generated from these sources. Given the availability of these resources in Canada, and given appropriate planning, there are no inherent constraints to producing electricity to meet demands considerably higher than the Reference Case.

Overall, the electrical industry at present has adequate reserve generating capacity. The situation varies from province to province, with some having excess capacity and, others not. In some instances the surplus capacity is in plants with higher than average operating costs, which producers would not intend to operate except in emergencies.

CHAPTER 6

NATURAL GAS

We begin this chapter by looking at established reserves and reserves additions in the conventional producing areas. We next examine current reserves in the frontier areas, and discuss potential supply from very low permeability sources in Western Canada. Our deliverability projections for both the conventional and frontier areas follow.

We then discuss exports and primary demand. We conclude with supply/demand balances for the conventional areas alone, and with frontier supply added.

6.1 Supply of Natural Gas

Historically, Canada has relied on the Western Canada Sedimentary Basin and parts of Eastern Canada, commonly referred to as the conventional producing areas, for its natural gas. More than 99 percent of current supply comes from Western Canada.

When reserves of natural gas in these areas approach depletion, Canada will become more dependent on alternative natural gas supplies from sources such as the frontier regions and very low permeability reservoirs. The frontier regions include the Mackenzie Delta, Arctic Islands and all of Canada's offshore regions. Very low permeability reservoirs which cannot be produced by conventional methods are encountered in West Central Alberta and the adjacent part of British Columbia.

The future supply of natural gas from any source is dependent on many factors, including exploration success, market price expectations, development and operating costs, prevailing fiscal regimes, and development of new technologies.

Reserves and Reserves Additions

Established Reserves

Established reserves are those reserves which have been discovered and which are considered recoverable under current technology and present and anticipated economic conditions. Initial established reserves refer to reserves prior to the deduction of any production, while remaining established reserves are those reserves left after cumulative production is accounted for.

Our estimate of Canada's initial established marketable reserves of natural gas including frontier regions is 148 exajoules as of 31 December 1982. This estimate results from a summation of individual pool estimates. Cumulative production, to this date, is 49 exajoules, leaving remaining reserves of 99 exajoules (Table 6-1). Our preliminary estimates as of the end of 1983 are also shown in Table 6-1.

The annual growth of natural gas reserves is a function of the exploration and development effort and the success of that effort. During the early 1970s, the incentives for development of natural gas reserves were limited. Since 1975, increased natural gas prices and associated improvement in producer netbacks coupled with the perception of growing export opportunities, resulted in an accelerated exploration and development effort, which continued until about 1981. This activity translated into a higher growth rate for natural gas reserves additions (Figure 6-1). Thus far in the 1980s, adverse economic conditions contributed to a slowdown in activity leading to lower reserves growth.

Reserves Additions

The major uncertainty affecting our natural gas supply forecast is the projection of reserves additions. Reserves

Table 6-1
Estimated Established Reserves of Marketable Natural Gas at 31 December 1982

(Exajoules)

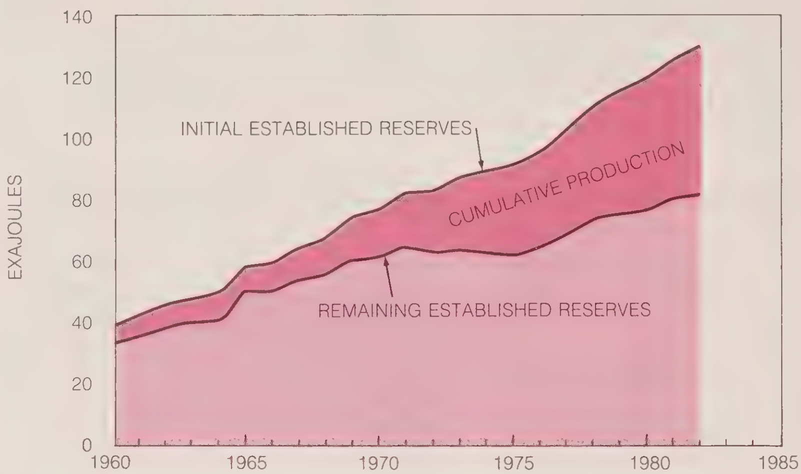
	Initial	Remaining
British Columbia	15.9	9.7
Alberta	109.6	69.3
Saskatchewan	2.8	1.7
Southern Yukon and Northwest Territories	0.6	0.4
Ontario and Other Eastern Producing Areas	1.1	0.3
Total	130.0	81.4
Mackenzie Delta	5.6	5.6
Arctic Islands	12.0	12.0
Canada Total	147.6	99.0
Preliminary Estimates as of 31 December 1983:		
Canada Total	149.9	98.5

additions are added to established reserves by appreciation of existing reserves (extensions to defined pools and revisions to previous estimates) and by new discoveries. The rate of reserves additions is dependent upon the level of drilling activity, which in turn is influenced by perceptions of ultimate potential and of the financial return producers expect to earn on their investment. Analysts have developed a number of approaches for estimating future annual additions, but in our view the exercise remains one of judgment and it is not surprising that the forecasts submitted to us manifest widely divergent views.

With respect to ultimate potential, it is important to recognize that the volume of gas that can be produced economically from any region is less than the total volume contained in the sediments of that region. The volume of the resource that is contained in the sediments is fixed and finite. The volume that can be produced economically, however, is a variable that depends on the supply cost and market prices. It follows that the ultimate potential cannot be assessed without reference to economics.

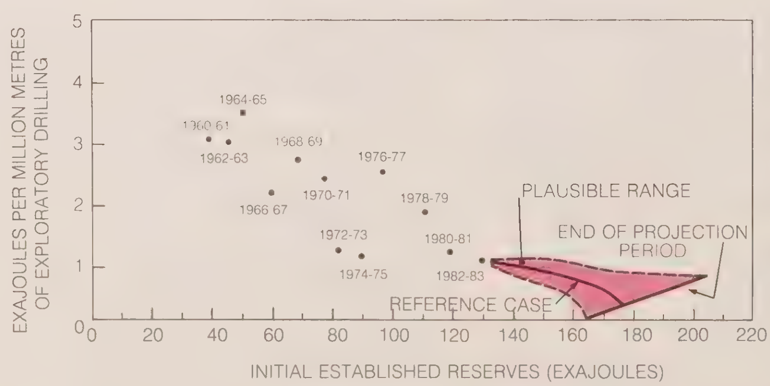
We find the historical decline in reserves additions per unit of exploratory drilling to be a particularly useful relationship in assessing the prospects for reserves additions. Figure 6-2 clearly illustrates this decline with respect to the Western Canada Sedimentary Basin. This figure may be interpreted in different ways, but it suggests a trend pointing to an ultimate potential between 170 exajoules and 200 exajoules. If it is assumed that the trend will flatten in the future, that is, the rate of reserves additions relative to drilling will tend to stabilize rather than continuing to decline, then the ultimate potential will be perceived to be even higher. Submittors' estimates of the ultimate potential of the Western Canada Sedimentary Basin range from 197 to

Figure 6-1
Established Reserves of Marketable Natural Gas Conventional Producing Areas



Source: Table A6-1, Appendix 6

Figure 6-2
Natural Gas Reserves Additions Per Unit of Exploratory Drilling, Conventional Producing Areas



Source: Table A6-2, Appendix 6

225 exajoules. The shaded area on Figure 6-2 represents the plausible range of reserves additions to 2005.

For our reserves additions projection (Figure 6-3), we accepted the range of ultimate potential suggested by the data on Figure 6-2 as a constraint on the quantity of new gas that could be anticipated during the forecast period. We then constructed an exploratory drilling profile reflecting this constraint. From this profile, and our projection of the rate of additions as a function of drilling activity shown in Figure 6-2, the Reference Case reserves additions forecast was developed. Finally, we examined the costs of these additions, to satisfy ourselves that financial viability could reasonably be expected.

Table 6-2
Social Supply Costs of Reserves Additions and Field Gate Prices Western Canada

($1983 per Gigajoule)

	1983	2005
Reference Case – Field Gate Price	2.48	3.60
Social Supply Cost of Reserves Additions	1.60	2.45

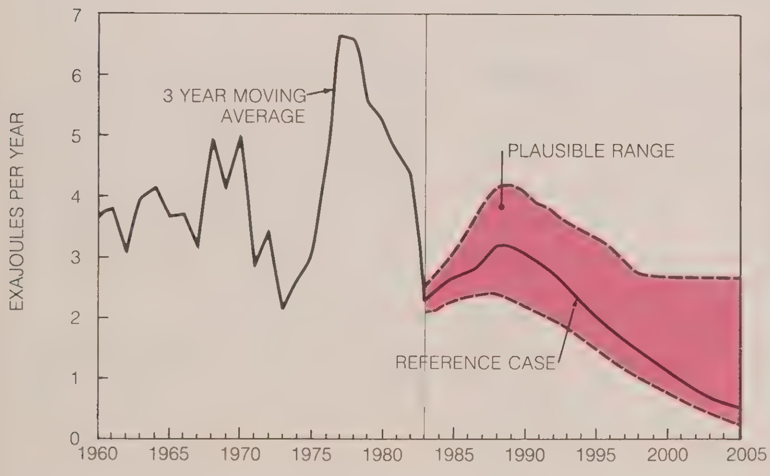
We considered only social supply costs in our analysis, that is, capital and operating costs exclusive of taxes, royalties and incentives, discounted at a real rate of ten percent, the estimated social opportunity cost of capital in Canada. We estimated these supply costs using four sequential reserves additions increments of ten exajoules. The timing of the ten exajoule increments reflects our drilling profile projection.

Table 6-2 indicates the expected rise in the marginal supply costs of reserves additions from $1.60 per gigajoule at the beginning of the period to $2.45 per gigajoule for the fourth ten exajoule increment. Over the same period, the field gate price (that is the price paid after field processing to produce marketable natural gas) is projected to increase from the current approximate value of $2.50 per gigajoule (including the flowback to producers of export revenue) to $3.60 per gigajoule.

The estimated supply costs appear to leave enough margin for taxes and royalties as to not invalidate our projection of reserves additions.

Our forecast of annual reserves additions is compared to submittors' views in Figure 6-4 and Table 6-3.

Figure 6-3
Marketable Natural Gas Reserves Additions
Conventional Producing Areas



Source: Table A6-5, Appendix 6
and Table A6-6, Appendix 6

Frontier Areas

We are in full agreement with submittors that the Canadian frontier re-

Table 6-3
Forecasts of Marketable Natural Gas Reserves Additions
Conventional Areas

(Exajoules)

	B.C.	Alta.	Sask.	Southern Terr.	Canada Total
AERCB	—	28.7[1]	—	—	—
Amoco (base)	5.1[2]	39.1[2]	1.3[2,4]	—	45.5[2]
(expanded)	8.4[2]	68.1[2]	1.3[2,4]	—	77.8[2]
B.C.	9.1	—	—	—	—
CPA	4.6[3]	31.9[3]	0.5[3]	0.5[3]	37.5[3]
Dome	11.3	59.8	3.6	—	74.7
Imperial	6.5[2]	45.6[2]	0.4[2]	0.4[2]	52.9[2]
Husky/NOVA	4.0	54.5	0.7	—	59.2
Petro-Canada	11.3	50.2	1.2[4]	—	62.7
Saskatchewan	—	—	3.5	—	—
Shell	10.4[2]	25.7[2]	—	—	36.1[2]
TCPL	6.4	40.6	—	—	47.0
NEB	5.4	39.3	0.8	—[5]	45.5

Gross heating values applicable to NEB estimate:

British Columbia	38.8 megajoules per cubic metre
Alberta	38.8 megajoules per cubic metre
Saskatchewan	36.8 megajoules per cubic metre
Southern Territories	36.8 megajoules per cubic metre

(1) From AERCB 84-18 report.
(2) Forecast 1983-2000.
(3) Forecast 1983-1995.
(4) Include Southern Territories and Ontario.
(5) Southern Territories included in British Columbia total.

gions have significant geological potential and could account for a substantial portion of future natural gas supplies. The quantities that will be exploited commercially and the timing of such production, however, will depend on many factors, including total volumes discovered, prevailing economic conditions, and technological progress. Uncertainties surrounding the development, production and transportation of natural gas from Canada's frontier areas make forecasting supply from this source extremely difficult.

Reserves potential is recognized in three frontier areas currently being explored: the Mackenzie Delta-Beaufort Sea, the Arctic Islands and the East Coast offshore. To date, there has been no production from any of these areas.

In the course of the 1977 Northern Pipeline hearing, the Board determined the established natural gas reserves of the Mackenzie Delta-Beaufort Sea region and the Arctic Islands to be some 6 exajoules and 12 exajoules, respectively. We consider these estimates still valid; additional quantities of gas have been found, notably in the Beaufort Sea, but these are not at present, in our opinion, established reserves. No natural gas reserves have yet been recognized by the Board for the East Coast offshore region, although several very interesting discoveries have been made. Delineation drilling will be required to establish the extent to which these may prove economically viable. We anticipate a hearing in the near future with respect to the Venture gas field, east of Sable Island, when it will be possible to fully evaluate reserves. Two wells, critical to an assessment, were drilling when this text was written.

Submittors' estimates of frontier reserves are compared with estimates of discovered resources[1] from the Canada Oil and Gas Lands Administration's (COGLA) 1983 Annual Report in Table 6-4.

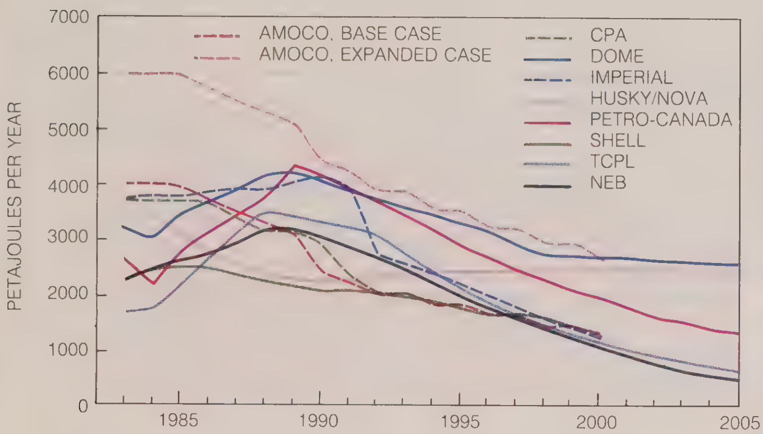
Very Low Permeability Sources

The Board has in the past acknowledged that a large resource of natural gas (tight gas) may well exist in very low permeability reservoirs, located in West Central Alberta and the adjacent area of British Columbia. It is generally accepted that any large-scale exploitation of these resources would require the application of non-conventional well completion techniques. In some areas, very low permeability reservoirs in direct contact with conventional reservoirs are expected to experience essentially conventional recoveries. In the Elmworth, Sinclair and Wapiti fields, some 11 billion cubic metres of tight gas in contact with conventional reservoirs have been recognized by the Board as forming part of the established reserves.

Attempts were made during the late 1970s to produce gas from very low

(1) Discovered resources are estimates of the quantities of crude oil or natural gas occurring in known reservoirs but of uncertain economic viability.

Figure 6-4
Projections of Marketable Natural Gas Reserves Additions
Conventional Producing Areas



Source: Table A6-7, Appendix 6

permeability reservoirs in Alberta by applying the massive hydraulic fracturing technique. Post-fracture flow rates, however, were not considered economic.

We agree with submittors that very low permeability reservoirs, unless overlain by conventional reservoirs, are currently not economically exploitable. Furthermore, to produce gas from non-conventional reservoirs economically, major advances in well completion technology will have to be made. Any future plan to exploit this resource will have to be weighed against alternate supply sources in terms of cost/price relationships.

Deliverability

The outlook for natural gas deliverability has changed very little since the Board's 1982 Gas Export Omnibus Hearing. In fact, most submittors provided the same forecasts as for that hearing, with certain minor adjustments to reflect greater cumulative production and changes in expected levels of demand. Submittors' forecasts of deliverability from established reserves, from established reserves and reserves additions combined, and from frontier regions are shown in Appendix 6, Tables A6-8, A6-9 and A6-10. There is close agreement in the forecasts of deliverability from established reserves, but there is a greater divergence of opinion when the more speculative reserves additions and frontier sources are included. Figures 6-5 and 6-6 compare submittors' forecasts of supply from conventional and frontier areas respectively with our Reference Case projection.

Table 6-4
Remaining Reserves and/or Discovered Resources of Natural Gas
Frontier Regions

(Exajoules)

	Mackenzie-Beaufort	Arctic Islands	East Coast Offshore
Amoco	8.0	14.5	—
COGLA[(1)]	10.7	14.2	9.1
CPA	22.9[(3)]	—	—
Dome	10.1	12.7	8.6
Gulf	9.3	16.0	12.0
Mobil	—	—	4.5
Panarctic[(2)]	—	17.8	—
Petro-Canada	—	14.6	12.0
NEB	5.6	12.0	—

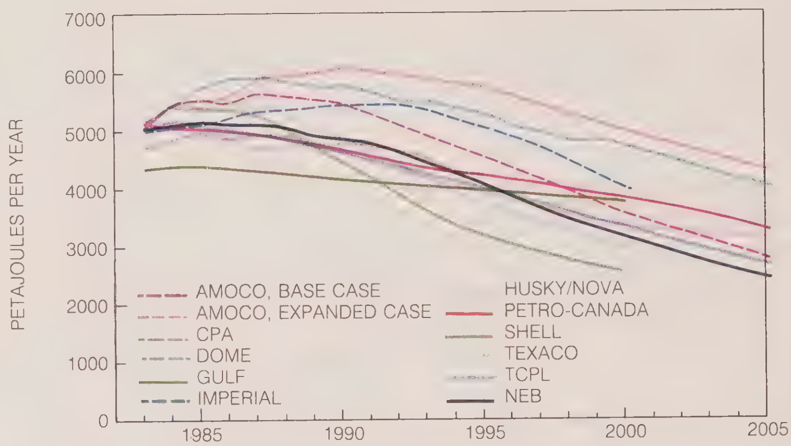
(1) Discovered Resources
(2) Proved and Probable only
(3) Includes Arctic Islands

Our Reference Case supply capability forecast is illustrated in Figure 6-7 and is detailed in Appendix 6, Tables A6-11 and A6-12. This supply capability forecast, described in more detail later, represents deliverability unconstrained by demand. Potential deliverabilities from frontier regions are shown for illustrative purposes. The frontier estimates, for the Scotian Shelf and for the Mackenzie Delta area, are based on proposed project levels of 10.1 million cubic metres per day of gas starting in 1990 and 22.6 million cubic metres per day of gas starting in 1995, respectively. We assumed that solution gas from Hibernia would initially be reinjected and, therefore, would not contribute to the total supply forecast. No other sources of frontier gas are considered likely during the forecast period.

Figure 6-7 illustrates that deliverability from controlled gas, that is, reserves now under contract in the conventional areas, will decline throughout the forecast period. Deliverability from other established reserves and from reserves additions is expected to equal supply from currently controlled reserves by the early 1990s, and to exceed it in the latter part of the projection period. Reserves additions therefore become a critical parameter in this forecast.

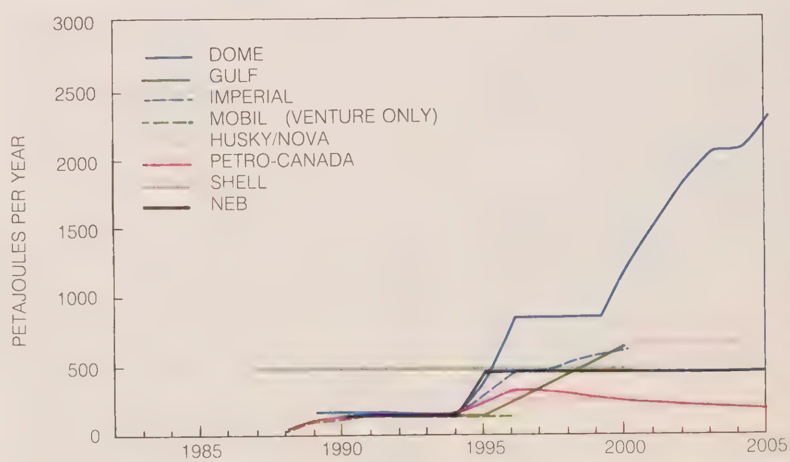
The various components of our gas deliverability forecast are shown in Appendix 6, Tables A6-11 and A6-12. Deliverability from over 90 percent of the controlled reserves is derived using our deliverability computer model. The forecast is based on a pool by pool analysis of gas deliverability reflecting well flow characteristics, basic reservoir parameters, and daily contract rates. The model incorporates drilling and compression cost data and current producer netbacks to economically maintain deliverability at or near the contract rate as long as possible by adding infill wells and/or field compres-

Figure 6-5
Projections of Deliverability Conventional Producing Areas



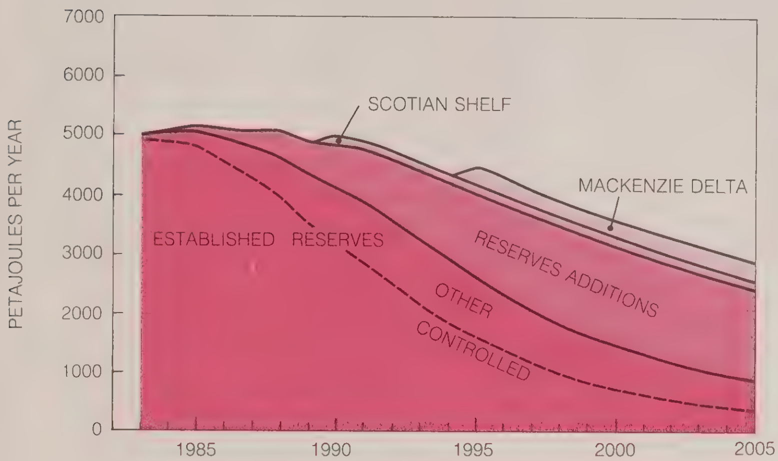
Source: Table A6-9, Appendix 6

Figure 6-6
Projections of Deliverability Frontier Regions



Source: Table A6-10, Appendix 6

Figure 6-7
Deliverability — Supply Capability by Supply Source, Canada



Source: Table A6-12, Appendix 6

sion. The forecast of deliverability from the remaining 10 percent of the controlled reserves is based on either past production history or other published forecasts.

Our deliverability forecasts always assume that there will be adequate pipeline capacity to transport the forecast levels of deliverability. However, because of low levels of demand in recent years and relatively low forecast levels for the next few years, it will be some time before installed pipeline capacity becomes equivalent to our forecast deliverability.

In addition to deliverability from controlled reserves, our gas supply forecast also includes deliverability from both other established reserves (uncommitted or not contracted, beyond economic reach, and deferred) and from reserves additions.

We estimate that as of 31 December 1982, there were some 15.8 exajoules of uncommitted gas reserves in Alberta, 3.4 exajoules of which were in the shallow gas zones of Southeastern Alberta. Because of continuing low levels of demand for Alberta gas and the growing take-or-pay commitments of the major gas purchasers, we feel that these uncommitted reserves will be tied in more slowly than we had previously assumed. The connection schedules used in the current forecast are shown in Appendix 6, Table A6-13.

Deliverability from the shallow gas reserves is based on a deliverability profile generated by our model. The deliverability profile for the other uncommitted gas reserves is based on an initial rate of one unit of production a day for each 7000 units of recoverable reserves. This rate is assumed to be constant for eight years and then decline at 8.22 percent per year thereafter. This is a widely accepted general profile for conventional gas reserves.

In British Columbia, we estimate that as of 31 December 1982, there were some 2.2 exajoules of uncommitted gas reserves. Deliverability from these reserves was calculated on a pool by pool basis by the model with onstream dates assigned considering expected demand levels, size of pool and distance from existing pipelines.

Uncommitted gas reserves in Saskatchewan as of 31 December 1982 are estimated to be 0.4 exajoules. Because the Saskatchewan government now intends to reduce its purchases from Alberta and to produce more of its own gas to meet its needs, we assumed that these uncommitted gas reserves would likely be connected faster than those in Alberta and our previous profile for uncommitted reserves was used. This connection schedule is also shown in Appendix 6, Table A6-13. As these reserves are largely shallow gas reserves, their deliverability was calculated using the same shallow gas deliverability profile as for Alberta.

Deferred reserves are those quantities of established reserves which, for some specific reason, such as involvement in a recycling or pressure maintenance project, are not at present available for production. Some 3.7 exajoules of reserves are considered deferred in Alberta at this time, and we adopted a deliverability schedule prepared by TCPL for these.

Beyond economic reach (BER) reserves are those established reserves which, because of size, geographic location or composition, are not considered economically available at the present time. As of 31 December 1982,

there were some 1.8 exajoules of BER reserves in Alberta and a further 0.7 exajoules in British Columbia. We assumed that 50 percent of the Alberta BER reserves would become available during the forecast period. They were connected at a rate of four percent per year and were produced using the uncommitted Alberta reserves deliverability profile described earlier. British Columbia BER reserves were included in the uncommitted reserves forecast for that province and were connected in a manner consistent with their size and location.

The connection schedule for reserves additions used in previous Board publications and shown in Table A6-13 was considered to be still appropriate and was applied to our reserves additions forecasts. Deliverability from reserves additions in Alberta and British Columbia was calculated with the same deliverability profile described earlier (i.e., an initial rate of 1:7000 and a flat life of eight years with production declining at 8.22 percent per year thereafter). We used the shallow gas profile to forecast deliverability from Saskatchewan additions.

Testing the sensitivity of our total forecast to different deliverability profiles for reserves additions showed that the quantity of reserves additions rather than the profiles or connection schedules has the greatest effect on long term deliverability. Consequently, the expected range of uncertainty in our overall supply forecast is principally dependent on the expected range of reserves additions. The effect of the uncertainty involved is discussed in the supply/demand balance section of this chapter.

6.2 Natural Gas Exports

Natural gas exports, which averaged some 1 000 petajoules per year during the 1970s, have declined during the last four years to 750 petajoules in 1983. This is only 40 percent of the level of exports currently authorized by the Canadian government. Declining United States demand for gas, the higher cost of the Canadian supply and increased United States supply generated by higher prices, have decreased the market opportunities for Canadian gas. Our exports represent only four percent of the United States gas demand; consequently, small swings in either demand or supply in that country can have a major impact on Canadian exports. The outlook for gas exports depends not only on future supply and demand, but also on modifications to gas pricing policies currently under review in both countries.

With respect to pricing, it was assumed that Canadian gas will become more market sensitive, with prices tending towards the level necessary to be competitive with indigenous United States gas and alternative fuels. This assumption is in line with the views provided to us in the submissions and in meetings held with exporters, and with the subsequent federal policy statement of 13 July, 1984.

No such unanimity exists with respect to the duration of the current excess gas deliverability in the United States. The situation has been imaginatively described by some experts as a bubble and as a sausage by others. In the longer term (post 1990), most agreed that a strong demand will exist for Canadian gas and that currently authorized quantities will be exported. In the period to 1990, our approach was to examine both the implications of the overall United States gas balance and the prospects for specific markets being served by existing licences. Considerable judgment was then used to make a forecast for each licence, the results of which are shown in Appendix 6, Table A6-14.

United States Supply and Demand

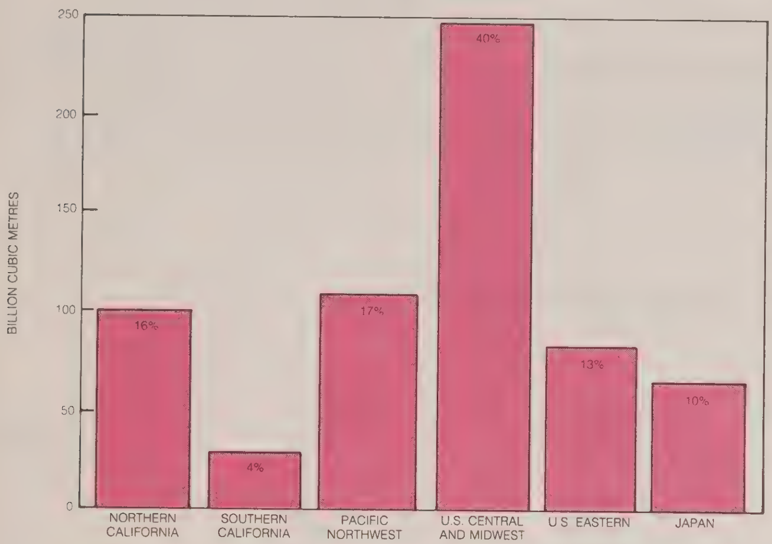
Our forecast of exports reflects the overall view that United States requirements for supplemental gas supplies (imports) would be about 31 billion cubic metres (1.1 Tcf) in 1986 increasing to 51 billion cubic metres (1.8 Tcf) by 1990. On the demand side, we see a modest increase in total United States gas demand from some 480 billion cubic metres (17 Tcf) in 1983 to 500 billion cubic metres (18 Tcf) in 1990. We do not expect reserves additions in the United States to keep pace with this level of demand during the next few years, with the result that the current deliverability surplus from the lower 48 states will become a shortfall by 1986. This, coupled with the effects of the current high rates of take from established reserves which will lead to a more rapid decline in future deliverability, point to a growing gap that the United States will have to fill from supplemental sources. Expectations are that Mexico and Algeria will continue to supply between 3 and 4 billion cubic metres (100 to 150 Bcf) per year. The remaining requirements for supplemental gas would be filled by Canadian imports.

Regional Market Considerations

The quantity of gas that is authorized to be exported to various United States markets is shown in Figure 6-8.

Northern California is served by Pacific Gas and Electric which purchases Canadian gas from Alberta & Southern Gas Co. Ltd. through its subsidiary Pacific Gas Transmission Co. Demand for Canadian gas declined in the 1982-83 contract year from the 1981-82 level, owing in part to high levels of rainfall that increased the availability of hydroelectric power. Surplus petroleum, principally residual fuel oil, which resulted from increased availability of Alaskan oil, has further compounded the marketing problems

Figure 6-8
Authorized Gas Exports by Market Region[1]



[1]as of 31 October, 1983

for Canadian gas even though Canadian exports to this market area enjoy low transportation costs both in the United States and in Canada. Currently, Canadian gas competes primarily with domestic supplies in the United States brought into northern California by El Paso pipeline. The Diablo Canyon and San Onefre nuclear plants are likely to displace some gas-fired electric generation when they come on stream.

Despite this competition, Canadian gas is expected to maintain its current share of the market in 1983-84, with exports at a level of 55 percent of authorized volumes. It is expected that takes of Canadian gas will gradually increase to 75 percent of the authorized quantity by 1986-87.

Canadian gas is sold into Southern California by Pan-Alberta to its United States importer, Northwest Alaskan, which resells the gas to Pacific Interstate Transmission for subsequent delivery to Southern California Gas Company. The major load centre for this gas is in the Los Angeles area. Here, Canadian gas competes with United States domestic gas from El Paso and Transwestern. We are forecasting that deliveries, which are currently 43 percent of authorized levels, will increase to 60 percent by 1986-87.

The present high cost of Canadian gas exports, combined with competition from low cost, high sulphur residual fuel oil, wood wastes, United States indigenous gas and electricity in the Pacific Northwest have caused a substantial reduction in export quantities to this market area. Based on the assumption that Westcoast's United States customer Northwest Pipeline, will continue to purchase gas from United States indigenous sources at the historical level of some 4.7 billion cubic metres (165 Bcf) a year, it is anticipated that the market for Canadian gas will gradually improve from the current 35 percent of the authorized level to 75 percent by 1986-87.

Potential for growth in the United States Central and Midwestern markets is limited primarily by population increases and industrial growth, neither of which is expected to be substantial in the short term. However, improved economic conditions and declining deliverability of United States gas available to interstate pipeline companies serving this region are expected to lead to increased demand for Canadian gas beginning in 1986.

Various Canadian companies serve this market area. Pan-Alberta exports, via the Eastern Leg of Foothills Pipeline (Yukon) Ltd., serve three United States pipelines, Northern Natural, Panhandle Eastern and United. Canadian gas is also sold by ProGas and Consolidated through the Northern Border system which makes up the United States portion of the Eastern Leg. TransCanada exports major quantities of gas at Emerson, Manitoba to its United States customers, Great Lakes, Midwestern and American Natural Resources Pipeline. Domestic United States gas, however, can currently be delivered into this area well below the price of Canadian gas.

United States customers of Canadian gas in the Central United States market area have experienced some permanent load losses due mainly to restructuring of industry and, in certain instances, competition from coal. As well, a substantial proportion of industrial customers in this region have dual-fuel capability and can readily switch between natural gas and residual fuel oil.

Canadian-Montana Pipe Line Company and Inter-City Gas Corp. both have suffered permanent load loss to coal and wood wastes in their market regions. Increased production of indigenous Montana gas has also had an impact on the demand for Canadian gas in Montana.

We forecast that deliveries to this region will increase to between 60 and 70 percent of the authorized level by 1986-87, from current levels of between 40 and 50 percent.

In United States Eastern markets there is considerable potential for expanded natural gas usage in the residential and commercial sectors as a result of substituting gas for oil in this region. Canadian exports currently moving into this market form a very small proportion of total exports primarily due to lack of pipeline facilities.

Demand in this region is forecast to remain at 1982 levels through 1984, with gradual improvements thereafter. New industries and an increase in conversions from other fuels are likely to increase requirements for natural gas. The increase in industrial demand should also help to improve system load factors.

We assume that TCPL's exports to Boundary Gas, Inc. will commence as scheduled in November 1984. All other new exports to the United States Northeast market, authorized as a result of the Board's 1983 Gas Export Omnibus Decision, will start during the 1986-87 licence year.

We forecast that deliveries will increase to 75 percent of the authorized level by 1986-87 assuming United States regulatory approval is received and proposed pipeline facilities are built to accommodate increased imports from Canada.

For purposes of this report, we assumed that the project sponsored by Dome Petroleum Ltd. to transport LNG from British Columbia to Japan would proceed, but that it would not start until 1987-88.

Short Term Forecast of Exports

The results of our forecast are summarized in Table 6-5 and are compared with submittors' forecasts in Figure 6-9.

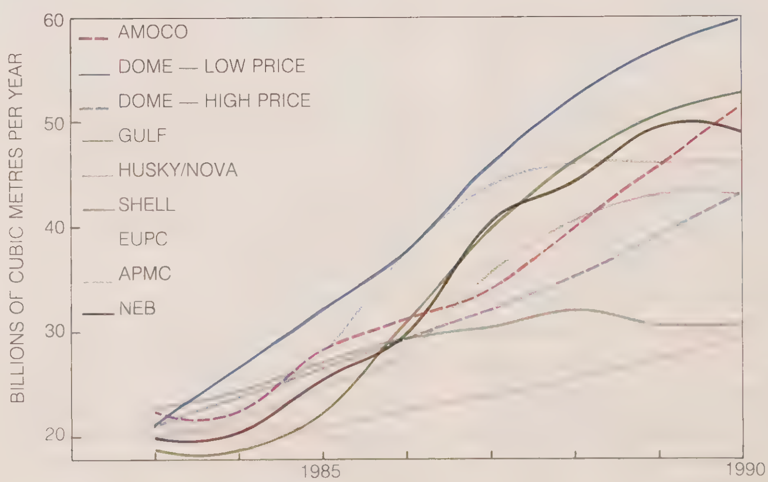
Beyond 1990, all submittors assumed extension of export licences. This assumption is not built into our forecast, which is based only on present licence terms and quantities.

Table 6-5
Short Term Forecast of Natural Gas Exports

(Exajoules)

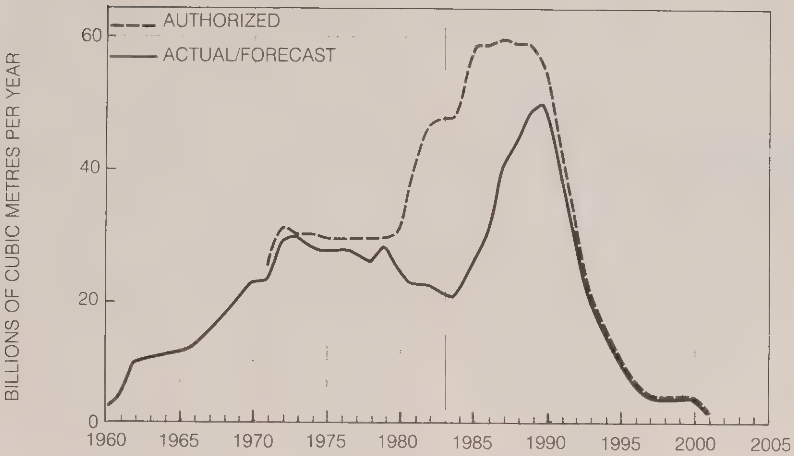
	Authorized Exports	Forecast Exports	Percent
1984	1.86	0.79	42
1985	2.22	1.01	45
1986	2.25	1.14	51
1987	2.26	1.53	68
1988	2.24	1.67	74
1989	2.22	1.85	83
1990	2.06	1.85	90

Figure 6-9
Projections of Short Term Natural Gas Exports



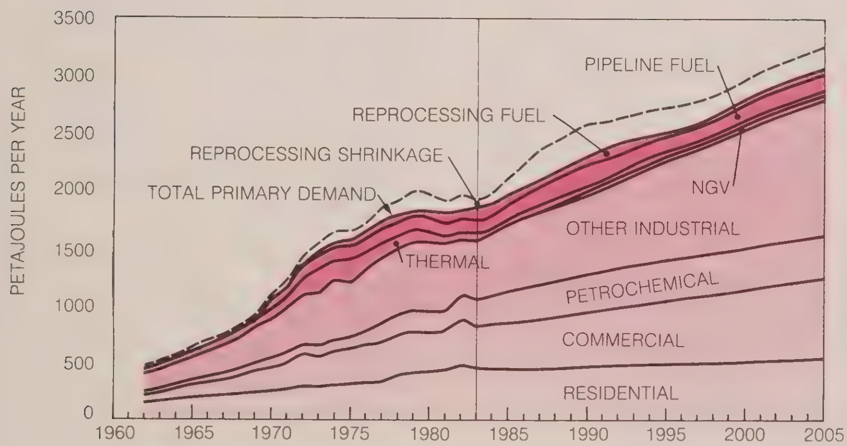
Source: Table A6-15, Appendix 6

Figure 6-10
Authorized, Actual and Forecast Natural Gas Exports



Source: Table A6-16, Appendix 6

Figure 6-11
Demand for Natural Gas, Canada



Source: Table A6-15, Appendix 6
Table A10-2, Appendix 10

Figure 6-10 illustrates our assumption that over the longer term export levels will track authorized levels.

6.3 Primary Demand for Natural Gas

Primary demand for natural gas includes requirements for thermal electricity generation, pipeline fuel and reprocessing fuel, as well as end use requirements. Figure 6-11 shows our Reference Case projection for primary gas demand (Appendix 10 provides demand levels). We project average growth in primary requirements for natural gas to be from two to three percent per year over 1983 to 2005. Our outlook on primary gas demand is compared to submittors' projections in Figure 6-12, and in Appendix 6.

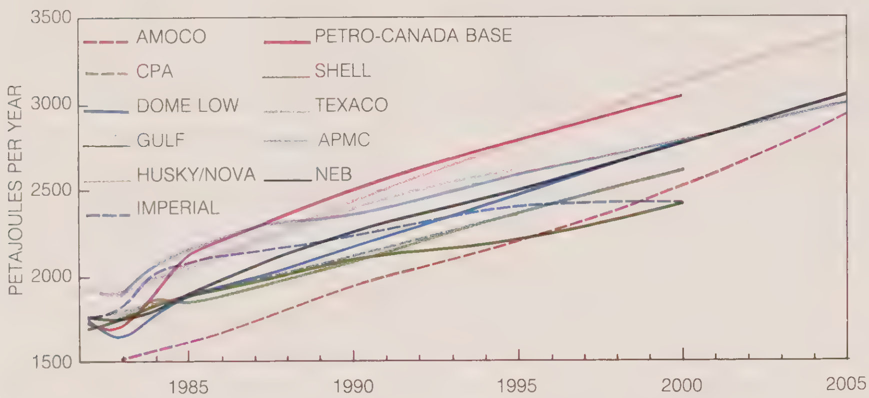
Considerable uncertainty exists about the impact of a number of factors on gas demand. Of particular importance are the outcome of the current competition between gas and electricity under current pricing policies, and the timing of extensions of natural gas service areas.

In general, primary gas demand tracks domestic end use requirements but thermal electricity generation requirements are projected to decline over the projection horizon (Chapter 5). Pipeline fuel increases significantly in the 1980s and subsequently declines, following the pattern of natural gas exports.

Our views on end use demand for natural gas follow from:

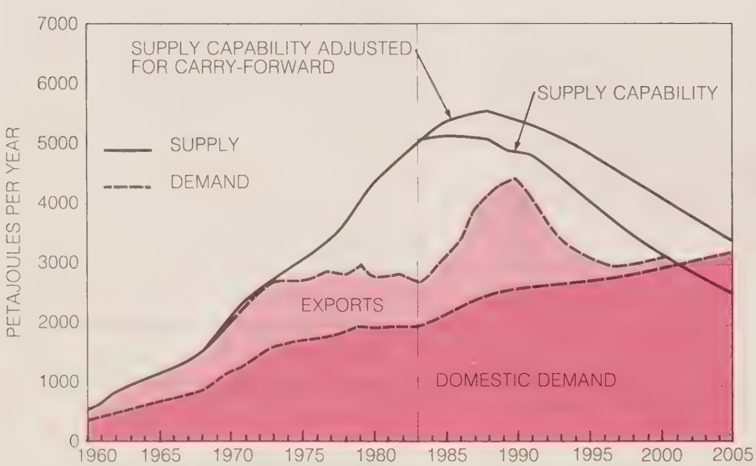
- our assessments of total energy demand in the residential, commercial and industrial sectors (Chapter 3) and of interfuel competition in those markets (Chapter 4),
- the extent of natural gas use as a petrochemical feedstock and fuel (Chapter 3); and

Figure 6-12
Projections of Primary demand for Natural Gas, Canada



Source: Table A6-18, Appendix 6

Figure 6-13
Natural Gas Supply and Demand
Conventional Producing Areas



Source: Tables A6-19 and A6-20, Appendix 6

- the use of natural gas for vehicles (Chapter 3).

End use demand is projected to grow at about 3.5 percent per year in the 1980s. Relatively rapid growth is projected as a result of the impact of economic activity on industrial energy markets, increasing gas penetration as natural gas service areas are extended in domestic markets, and increased use of natural gas as a petrochemical feedstock. In the 1990s, demand is projected to grow at about 2.5 percent per year, as gas penetration slows, and as growth in petrochemical requirements is considerably reduced. We have assumed that natural gas would increasingly be used as a vehicle fuel, especially in commercial fleets.

6.4 Supply/Demand Balance

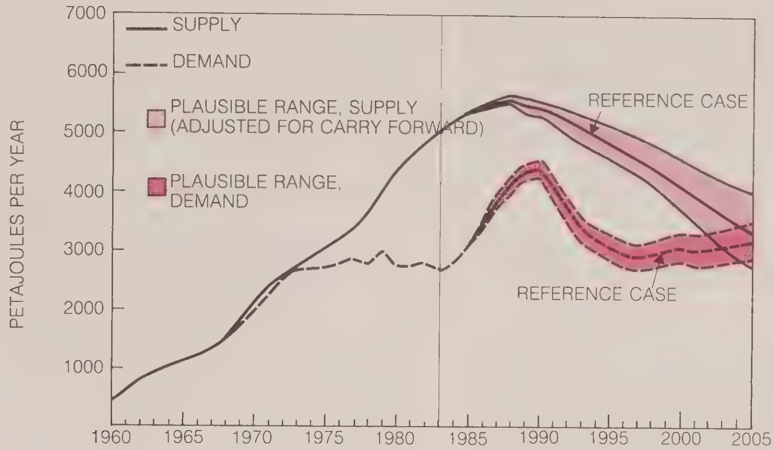
Figure 6-13 compares the gas supply forecast for conventional areas to the projection of domestic and export demand, excluding domestic demand in the Atlantic regions. This demand has been excluded because it is predicated on an East Coast offshore gas source.

The higher of the two supply lines in Figure 6-13 reflects the impact of carrying forward to subsequent years natural gas unused in the earlier years of the projection period. It is evident that, given our Reference Case supply and demand projections, there will be an excess supply of natural gas until the turn of the century.

The plausible ranges of gas supply and demand are illustrated in Figure 6-14. The shaded demand area represents the deviation from the reference forecast. Similarly the shaded area of supply represents the deviation adjusted for the carry-forward of surplus deliverability. Overall, natural gas supply from the conventional producing areas is expected to meet demand

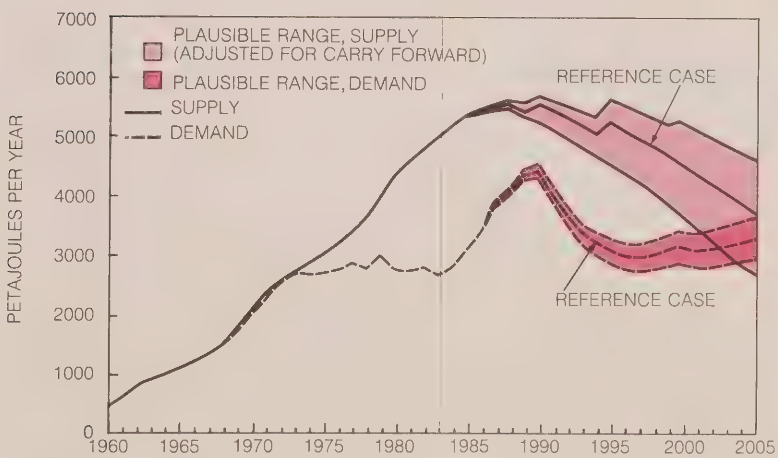
for at least 20 years, perhaps considerably longer. This outlook is not materially affected by the inclusion of our projections of frontier supply and Atlantic demand. (Figure 6-15)

Figure 6-14
Plausible Ranges
Natural Gas Supply and Demand
Conventional Producing Areas



Source: Table A6-19, Appendix 6

Figure 6-15
Plausible Ranges of Natural Gas Supply and Demand, Canada



Source: Table A6-19, Appendix 6

CHAPTER 7

CRUDE OIL AND EQUIVALENT

In this chapter we examine the extent to which Canada's oil resources can satisfy domestic demand for petroleum products. After introducing the various components of the oil resource, the different supply sources are discussed beginning with supply from conventional producing areas – primarily in Western Canada. The discussion includes a review of currently remaining established reserves as well as reserves additions from future discoveries, enhanced recovery, and other appreciation of reserves in established pools. Next we assess the likely contribution of synthetic crude oil and crude bitumen from oil sands deposits, and finally we look at the prospects for production from frontier areas – the Mackenzie Delta – Beaufort Sea, the Arctic Islands and the East Coast offshore.

We then discuss oil demand which is based on the demand for specific petroleum products. Domestic refinery feedstock requirements are related to available domestic supply and the implications for future imports and exports examined. We conclude the chapter with a discussion of the supply/demand balance.

7.1 Supply of Crude Oil and Equivalent

There are three major constraints that affect future oil supply:

- The size of the oil resource.
- Technological limitations which influence the accessibility of resources for exploitation, the level of recovery from deposits and the lead time required for development.
- Economic considerations which affect the pace of resource exploitation and recovery levels.

The crude oil resource base is the total quantity of hydrocarbon known or inferred to exist from which crude oil or its equivalent can be obtained, without regard to that proportion which may prove economically recoverable. Only part of the resource base will ultimately constitute supply, depending on geological, technological and economic factors.

The resource base is made up of components which are diverse and not equally well defined. That best defined is oil in place in discovered pools. These pools, which contain our established reserves, encompass a wide variety of reservoirs containing crude oil of different quality and having very different production characteristics. Production rates will normally decline as a pool is produced, but the rate of decline can be reduced and the recovery of oil increased as technological progress occurs and as producer economics make feasible more complex and generally more expensive enhanced recovery processes. Oil in place in discovered pools is about four percent of the total resource base.

Less well defined are future additions to the conventional crude oil resource base through exploration and development. These could amount to some five percent of the resource base. In well explored regions a reasonable estimate of additions can be made through analysis of past discovery trends but advances in exploratory techniques and changes in producer economics could well result in additions that vary significantly from historical trends. In less explored areas a geological assessment can be made, but favourable geological conditions do not guarantee the occurrence of oil, and estimates based on such assessments are very speculative. Because most of Canada's unexplored areas are offshore or in the Arctic regions, petroleum resource development in these areas will be very expensive, and the economic viability of any discovery will depend on reservoir size and productive capacity.

By far the largest component of the crude oil resource base, but least well defined in terms of exploitable quantities, is crude bitumen. It constitutes some 90 percent of the total. Crude bitumen is a tar-like substance which generally will not flow out of the deposits in which it occurs. Where the deposits occur near the surface the bitumen can be recovered by mining techniques. Deposits occurring in the subsurface must be produced through wells following the introduction of heat to make the bitumen mobile. The latter production method is referred to as in situ recovery.

Crude bitumen occurs in several very large deposits in Alberta each with its specific challenges with regard to extraction. Two large mining plants are currently in operation in the Athabasca deposit. The bituminous sand is recovered from open pits, the bitumen and sand separated by a hot water process, and the bitumen then upgraded by a refinery process to a synthetic crude oil. Smaller scale in situ projects are in operation at several locations in the province. Production from these is currently not upgraded; the produced bitumen is mixed with pentanes plus (a very light oil derived for the most part from natural gas processing) to thin the bitumen and make it suitable for pipeline transportation.

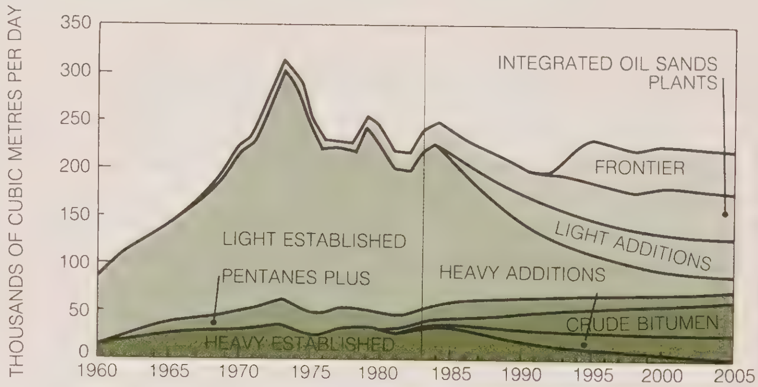
Though currently available technology is capable of developing a sizeable portion of the resource, it is very expensive. Several proposals to increase bitumen extraction efficiency are, however, under development and significant progress appears likely over the forecast period.

Synthetic crude oil produced from coal could also be considered part of the oil resource base. Two plants are currently operating in South Africa. In Canada research is taking place on the liquefaction of coal from both Eastern and Western coal deposits.

Estimates of social supply costs provide a measure of the economic feasibility of developing Canada's oil resources. Table 7-1 shows estimated ranges of social supply costs for various sources of oil supply. These are costs of developing and producing oil exclusive of taxes, royalties and any incentives, discounted at a real rate of ten percent, the estimated social cost of capital in Canada. The ranges given for each supply source reflect uncertainties in input data, and indicate that supply costs will differ from project to project within a given supply source.

The estimates were constructed on the assumption that real costs would rise as the resource base diminished, but that there would be no real increase in capital and operating costs per unit of effort.

Figure 7-1
Production History and Projected Productive Capacity of Crude Oil and Equivalent Canada



Source: Tables A7-3 and A7-1, Appendix 7

Table 7-1
Oil Prices and Social Supply Costs of Crude Oil[1]

	$1983 Per Cubic Metre
World Price of Oil at Montreal[2]	
1983	215 – 265
2005	250 – 310
Conventional Reserves Additions	70 – 140
Enhanced Recovery, Heavy Oil	60 – 160
Enhanced Recovery, Light Oil	60 – 210
Frontier[3]	100 – 150
Integrated Oil Sands Mining Plants	200 – 300
Integrated Oil Sands In Situ Plants	200 – 300
Bitumen and Upgrading	210 – 320
Bitumen	110 – 170
Upgrading	100 – 150

(1) Includes transportation costs to Central Canada except where otherwise indicated.
(2) Indicated price range is for oil in the APMC D7-S7 to D2-S3 quality range.
(3) Excludes transportation costs. Transportation costs depend on location of fields, and may range from $10 – $80 per cubic metre.

The ranges of supply costs are shown in order of perceived economic attractiveness and are, in our opinion, representative. The relative costs of production from alternative sources of supply were a key consideration in the preparation of our forecast. Only one submittor, Dome, provided supply cost estimates from several supply sources; its estimates are comparable to ours. Further reference to these supply costs will be made in discussing individual supply categories.

Our forecast of supply of crude oil and equivalent is summarized in Figure 7-1. It is evident that by the year 2005 currently established reserves will be providing only a small proportion of total supply. New supplies will come from discoveries, enhanced recovery of currently established reserves, oil sands projects and the frontier regions. An increasing proportion of total supply will be from the heavy oil category, thus

heavy crude oil to a lighter oil, or for increasing exports of heavy oil with a compensating increase in imports of light crude oil.

Supply from Conventional Areas

Established Reserves

Established reserves are shown by province in Table 7-2. These estimates were compiled on the basis of individual pool performance reviews.

During the forecast period productive capacity from established reserves is expected to decline from a level of 200 000 cubic metres per day in 1983 to a level of 19 000 cubic metres per day in 2005, or about ten percent of the current level. Our forecast of productive capacity from established reserves is not sensitive to world oil prices as we assumed incentives for infill drilling and programs of fiscal relief for marginal pools will continue. Hence, the plausible range which is indicated in Table 7-3 is very limited.

The Reference Case forecast of productive capacity from established reserves is summarized by province in Appendix 7, Table A7-4 and detailed by pool in Appendix 7, Table A7-5. In this table we have also grouped the individual pool data according to pipeline system. This aggregation provides an assessment of the projected utilization of individual pipelines which enables possible pipeline constraints to the forecast to be identified. The locations of these and other major pipelines are shown in Figure 7-2.

Table 7-2
Estimated Established Reserves Of Conventional Crude Oil At 31 December 1982

(Million Cubic Metres)

	Initial	Remaining
British Columbia	80.4	23.9
Alberta	1868.9	567.8
Saskatchewan	392.6	100.4
Manitoba	29.1	7.5
Northwest Territories	39.9	35.6
Ontario	9.8	0.6
Canada Total	**2420.7**	**735.7**
Preliminary estimates as of 31 December 1983:		
Canada Total	**2466.8**	**714.5**

Table 7-3
Plausible Range of Productive Capacity From Established Reserves

(Thousands of Cubic Metres per Day)

	1983	1990	2005
High	210	104	20
Reference Case	200	99	19
Low	190	94	18

Reserves Additions of Conventional Crude Oil in Established Producing Areas

Reserves additions consist of future discoveries and appreciation of reserves in established pools. Appreciation results from revisions to previous estimates, extensions to a pool's boundaries and improvements in oil recovery through the application of enhanced oil recovery methods. Enhanced recovery can be achieved through infill drilling, waterflooding, or other, more costly methods, commonly referred to as tertiary techniques.

For our analysis we have considered reserves additions resulting from all forms of enhanced recovery of currently established reserves as one category. Future discoveries and other appreciation of currently established reserves are considered as a separate category. The magnitude of the reserves additions for each of these categories is illustrated in Figure 7-3.

The total reserves additions of conventional crude oil in conventional areas amount to 679 million cubic metres for the forecast period. In comparison, the Board forecast additions totalling 696 million cubic metres for its modified base case in its June 1981 report. The current forecast is less op-

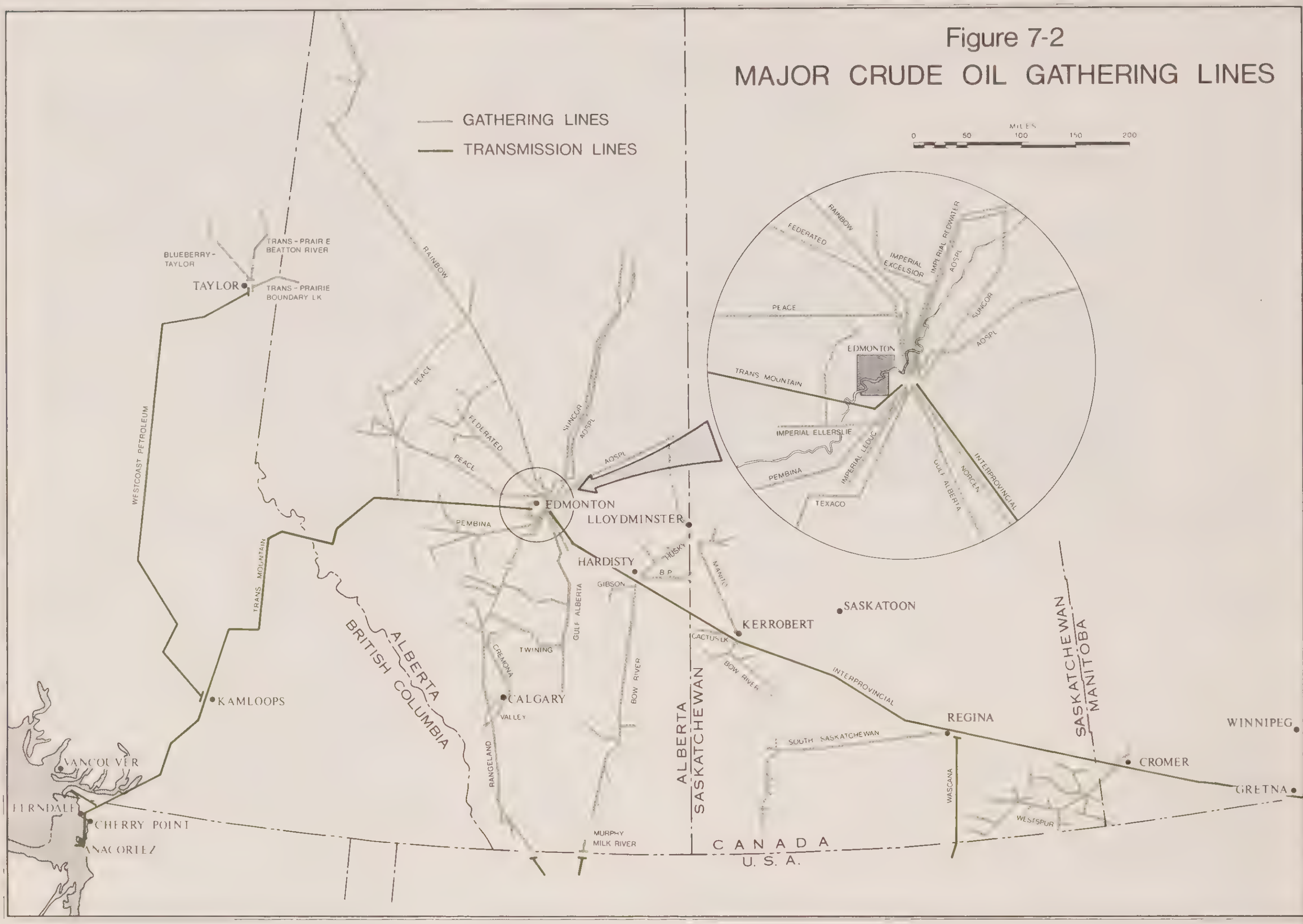


Figure 7-2
MAJOR CRUDE OIL GATHERING LINES

timistic with respect to anticipated additions from enhanced recovery of established reserves but more optimistic with regard to future discoveries. Figure 7-4 illustrates the profile of past and expected future reserves additions over the forecast period.

Productive capacity from reserves additions in the conventional producing areas amounts to 62 000 cubic metres per day by the year 2005. Because this represents about 30 percent of the total productive capacity forecast for that year, the importance of future reserves additions in attaining the productive capacity levels forecast is very evident. The basic assumptions used to convert reserves additions to productive capacity are listed in Appendix 7, Table A7-11.

Future Discoveries and Appreciation

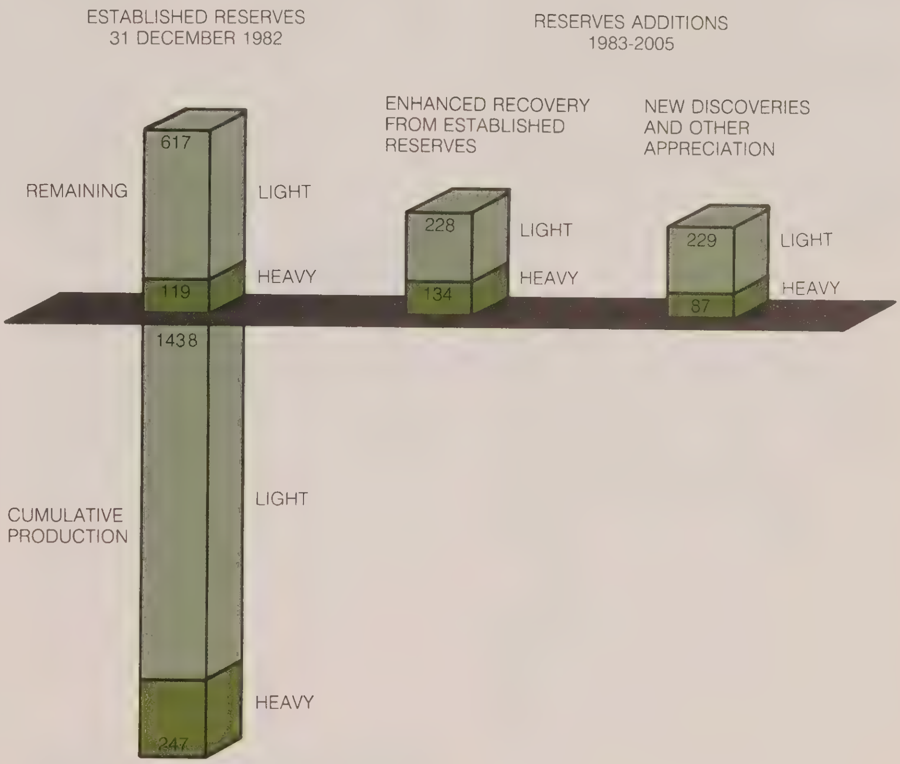
Crude oil reserves additions from new discoveries and appreciation, excluding appreciation of currently established reserves through enhanced oil recovery, are expected to account for about half of the total additions as shown in Figure 7-3.

During the early years of the forecast period, the level of reserves additions we project is comparable to that experienced annually since 1978, when additions increased considerably. This increase coincided with an accelerated exploratory drilling effort, much of which was gas directed. Subsequently, reduced interest in new gas and improved economics for oil development stimulated oil directed drilling and resulted in the continuation of the higher additions rate. We anticipate a strong oil directed exploratory effort to continue during the early years of our projection, which will maintain additions at levels currently being experienced. Later, we expect these will decline as oil becomes more difficult to find.

In the past, reserves in many oil pools appreciated significantly in the years

Figure 7-3
Reserves of Conventional Crude Oil Conventional Areas

(millions of cubic metres)



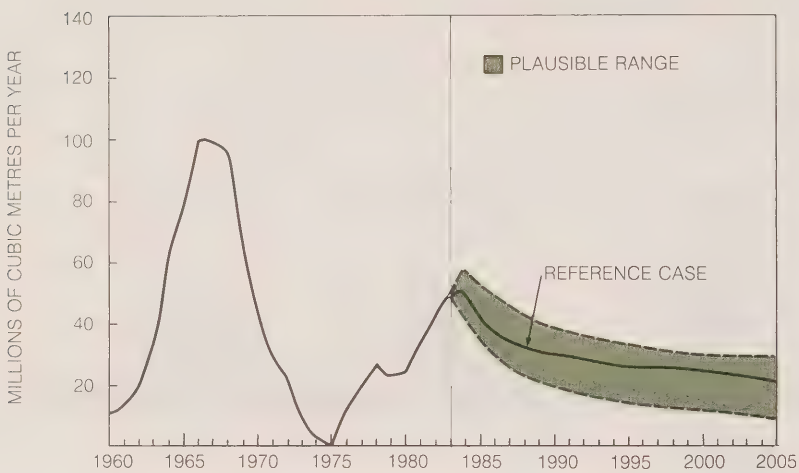
SOURCE: Tables A7-2, A7-6, and A7-8, Appendix 7

following discovery. The appreciation resulted from a combination of greater understanding of reservoir characteristics, pool development, and improved producer economics. At present, other than by enhanced recovery, we anticipate little overall appreciation from previously discovered pools, or from the smaller pools expected to be discovered during the forecast period.

We expect that the profitability of exploration and production of crude oil in Western Canada can be maintained throughout the plausible range of prices used for this report. The geological uncertainty or risk, on the other hand, may have a significant influence on the profitability of individual companies depending on the number and size of pools discovered.

The plausible range of reserves additions indicates the effect of higher or lower prices and geological potential. Lower oil prices resulting in lower pro-

Figure 7-4
Conventional Crude Oil Reserves Additions Conventional Areas[1]



Source: Tables A7-2, A7-6 and A7-8, Appendix 7

[1]Norman Wells Waterflood Excluded

ducer returns are expected to retard exploratory drilling effort, causing lower additions rates while higher prices are expected to accelerate exploration, yielding higher rates. The plausible range becomes considerably smaller in the later years of the forecast, as the ultimate reserves potential is approached. The corresponding range for the productive capacity forecast is given in Table 7-4.

Enhanced Recovery

In this report, enhanced oil recovery includes all recovery techniques other than those which utilize only the natural energy of the reservoir, known generally as primary techniques. While there is some potential for reserves additions by infill drilling and further waterflooding in established pools, the greatest potential for enhanced recovery is through the application of tertiary recovery techniques.

For light oils, the most common tertiary technique involves the injection of a fluid that is miscible under reservoir conditions with the oil. In the case of the hydrocarbon miscible process the fluid injected is an NGL such as propane, while in the case of the carbon dioxide miscible process it is carbon dioxide. For heavy oils, the most common tertiary processes involve steam injection or in situ combustion of the oil in the reservoir to enhance oil recovery. These are referred to as thermal techniques. Other processes such as surfactant, alkaline and polymer assisted waterfloods are expected to provide only minor amounts of incremental oil.

Recovery potentials for the various tertiary recovery processes were assessed with the aid of a project evaluation model. This model provides an estimate of the incremental oil recovery that would be obtained by the application of a tertiary process in a given reservoir and assesses the economic viability of the project. The data base for this model was developed by a screening process that identified those reservoirs where application of one of the tertiary processes was considered to be technically feasible. An aggregation of the results for individual pools provides estimates of both the total incremental recovery and that portion which is economically viable. The total incremental recovery is referred to as the technical potential while that portion considered economically viable is referred to as the economic potential.

The results of our assessment for the two most important enhanced recovery processes, miscible for light oil reser-

Table 7-4
Plausible Range of Productive Capacity From Discoveries and Appreciation[1]

(Thousands of Cubic Metres per Day)

	1990	2005
High	29	33
Reference Case	24	27
Low	20	21

[1] Appreciation of currently established reserves through enhanced recovery is excluded.

voirs, and thermal for heavy, are shown in Table 7-5. For the miscible processes the estimated technical potential is 304 million cubic metres which is 8 percent of the original oil in place in the pools analysed. For the thermal processes the estimated technical potential is 266 million cubic metres, which is 29 percent of the original oil in place in the pools analysed. Economic potentials for the Reference Case are 145 million cubic metres for the miscible processes and 170 million cubic metres for the thermal processes. The total original oil in place for reservoirs where at least one of the tertiary processes was deemed to be technically feasible amounts to 4650 million cubic metres, or about 60 percent of the original oil in place for conventional oil reservoirs in Canada.

For conventional heavy oil reservoirs it is generally accepted that unless some of the technical problems prove more serious than anticipated, the in situ combustion process will predominate. The reason for this is that much of Canada's conventional heavy oil is contained in relatively thin reservoirs. The steam injection processes are most likely to be successful in thicker zones and are therefore more applicable to recovery of bitumen from oil sands, where the pay zones can be relatively thick.

At the present time miscible processes are considered to be technically feasible for application in Canadian reservoirs, but other tertiary processes generally require further development before commercial scale projects can be implemented in this country. Since the introduction of the National Energy Program in 1980, economic risks associated with tertiary projects have been reduced through price provisions and reductions in royalties and taxes for incremental oil produced. As a result the industry has become very active in this area and new projects

Table 7-5
Enhanced Oil Recovery Model Results — Reference Case

	Thermal	Miscible
Original Oil In Place (millions of cubic metres)	909	3743
Technical Potential (millions of cubic metres)	266	304
Percent of Original Oil in Place	29	8
Economic Potential at Reference Oil Price (millions of cubic metres)	170	145
Percent of Technical Potential	64	47

have been initiated while many others are under consideration. these projects are largely experimental in scale but for the hydrocarbon miscible process several commercial scale projects are being implemented. Currently active and planned enhanced oil recovery projects are listed in Appendix 7, Table A7-12.

For the hydrocarbon miscible process, the reserves additions forecast in the first few years of the forecast period is based on a schedule of currently planned projects. Early in the forecast period we expect that NGL will be the preferred miscible fluid because of a surplus supply and low cost. During the 1990s we anticipate that carbon dioxide will be used to a greater extent because of decreasing availability and possibly increased costs of NGL. For our projection, we have assumed that almost all of the economic potential for the miscible processes will be added over the forecast period.

For the thermal processes, the additions were assumed to build up slowly as technological development proceeds. Only 60 percent of the economic potential is projected to be added over the forecast period. The forecast reserves additions for the various enhanced oil recovery techniques are detailed in Appendix 7, Tables A7-6 and A7-8.

Although much progress is being made in the development of enhanced oil recovery techniques, many technological risks remain. Any forecast of reserves additions from enhanced recovery projects therefore involves considerable uncertainty. Uncertainties also surround possible future changes to the fiscal regime applicable to enhanced oil recovery projects. Table 7-6 shows the sensitivity range for the economic potentials for the various enhanced recovery techniques. The corresponding plausible range for productive capacity is given in Table 7-7.

Pentanes Plus

The forecast of the supply of pentanes plus is included in this section because it forms part of crude oil and equivalent supply, although it is produced as a by-product of natural gas processing. It is discussed in detail with other natural gas liquids in Chapter 8.

Our forecast of pentanes plus production is summarized in Appendix 8, Table A8-12. This summary provides supply by gas plant, pipeline system, province and total Canada. Only part of this supply will be available as crude oil and equivalent because minor volumes are expected to be used in enhanced

Table 7-6
Economic Potential for Enhanced Oil Recovery of Established Reserves

(Millions of Cubic Metres)

	Low Price	Reference Price	High Price
Infill Drilling and Waterflooding	60	100	145
Thermal Processes	150	170	200
Miscible Processes	75	145	170
Other Processes	5	10	15
Total	290	425	530

oil recovery schemes. The remaining available pentanes plus supply, after allowing for our projected forecast miscible fluid requirements, is included in Appendix 7, Table A7-3.

The growth in the available supply of pentanes plus from the current level of between 14 000 and 15 000 cubic metres per day to nearly 18 000 cubic metres per day in 1989 is attributable to the projected increase in natural gas production. The subsequent decrease in supply is related to reduced gas exports, termination of major cycling schemes and a gradual decrease in the pentanes plus content of produced gas as reservoir pressures decline in older fields and the supply of solution gas from oil fields diminishes. The decrease in pentanes plus content in the total gas supply is aggravated by the assumption that future gas discoveries will contain less pentanes plus than the currently established reserves. A trend of diminishing pentanes plus content has been observed over the last decade.

A major use of pentanes plus is as a viscosity reducing agent to facilitate the pipeline transportation of heavy crude oils. We anticipate that the production of heavy crude oil will increase over the forecast period, largely because of the growth in bitumen production from oil sands deposits. Consequently, we expect that there will be an increasing demand for pentanes plus. Without an upgrader, demand will exceed supply by the late 1980s or early 1990s. All submittors who examined the supply/demand balance for pentanes plus also came to this conclusion. Solutions suggested by submittors involve the use of low quality refined light oils as a viscosity reducing agent in the transportation of heavy crude oils, or partial upgrading of the heavy crude oils to obtain the desired viscosity reduction. Conventional upgrading in a regional upgrader is also recognized as a possible solution.

Synthetic Crude Oil and Crude Bitumen Supply

The oil sands are a vast resource which, given an appropriate economic climate, could be developed to compensate for the declining supplies of conventional oil. The major economic factors that will determine the rate of this development are oil prices, fiscal terms, financing capability of the industry and markets. Government policies, both federal and provincial, can have a major impact on these factors. Consequently, there is a large degree of uncertainty in any forecast of future oil sands production.

It is generally accepted that the Alsands and Cold Lake oil sands projects were cancelled in the early 1980s because of an anticipated reduction in cash flows and uncertainty with regard to future oil prices. Since these cancellations, industry has moved to reduce the economic risks by opting for smaller projects. A recent change which is affecting oil sands development is the increased availability of markets for non-upgraded bitumen in the United States, due to a road repaving program and expanded upgrading capabilities of United States refineries.

The in situ oil sands extraction process is more suited to small scale operations than the mining process because economies of scale are less important. Husky/NOVA suggest that a size of 11 000 cubic metres per day is

Table 7-7
Plausible Range of Productive Capacity From Enhanced Oil Recovery of Established Reserves

(Thousands of Cubic Metres Per Day)

	1990	2005
Upper	19	48
Reference Case	16	35
Lower	12	16

optimum for a mining plant. By contrast the nature of the in situ production process lends itself to the addition of small increments, particularly if the bitumen is not upgraded.

In summary, current activity within the industry suggests that in the near term the oil sands will be developed by a phased approach employing the in situ process. In the near future, the product will not be upgraded but will be directed to satisfy a growing market in the United States. Later, regional upgraders could be constructed to process the production of several producers, and to provide a light grade refinery feedstock. These developments will occur as market conditions and/or diluent shortages make them appropriate. During the 1990s, when oil prices are expected to increase in real terms, mining operations should again become more attractive investments. However, considerable uncertainty surrounds the timing of such projects.

Today, the economics of crude oil upgrading are far from certain. Submittors generally agree that, while upgrading at an oil refinery could be economically attractive, a stand-alone upgrader would require concessions in royalties and taxes to be commercially viable. To be attractive, the price differential between upgraded and non-upgraded product must be sufficient to cover the cost of upgrading and provide a return to the investor. Currently, this price differential is only $50 to $75 per cubic metre while estimated upgrading costs range from $100 to $150 per cubic metre. For an upgrader at a refinery site, capital costs are 50 percent to 70 percent of those of a stand-alone upgrader. One currently active proposal is for an upgrader at the Federated Co-op refinery site in Regina. In early June, Husky and the Alberta, Saskatchewan and federal governments announced a financing arrangement for an upgrader in the Lloydminster area.

Our oil sands forecast is based on the considerations outlined above. We assume in situ production of crude bitumen will grow from the current level of 5000 cubic metres per day to 35 000 cubic metres per day in 2005. In the early years, this forecast is based on the identified projects listed in Table 7-8. With regard to upgrading we assume that the Federated Co-op upgrader will start up in 1988, and that the proposed Husky upgrader at Lloydminster will commence operation in 1989. In addition, we assume that capacity of the Husky upgrader is 7000 cubic metres per day and of the Federated Co-op upgrader is 8000 cubic metres per day.

With regard to oil sands mining plants, our forecast assumes that one plant will come on stream in 1992 and another in 1999. Capacity of both these plants is 10 000 cubic metres per day. Timing of the plants is largely determined by the need for about a seven year lead time for a mining plant and the problems of financing more than one plant at a time. Furthermore, taxes and royalties for synthetic projects have thus far been negotiated project by project. Under these conditions it is difficult to begin a new project until a prior project is succesfully completed. Thus a considerable time period between projects, to accommodate fiscal negotiations, engineering studies and construction is probable.

As previously mentioned, there is considerable uncertainty in any forecast of future supply from oil sands. We foresee that, depending upon economic factors, in situ bitumen production could be as low as 15 000 cubic metres per day or as high as 50 000 cubic metres per day in 2005. This could be

Table 7-8
Major Oil Sands and Upgrading Projects Included in Reference Case

	Size (Thousands of cubic metres per day)	Start-up Year
Oil Sands Plants		
Expansion of Syncrude	3.5	1988
New Medium Size Plant	10.0	1992
New Medium Size Plant	10.0	1999
In Situ Bitumen Production		
Wolf Lake	1.0	1985
Cold Lake (Phases I to VI)	9.0	1984-1991
Others	20.0	
Upgraders		
Federated Co-op	8.0	1988
Husky	7.0	1989

accompanied by no upgraders on the low side and possibly three upgraders on the high side. There could be no new mining plants, or as many as three during the forecast period, depending upon the economic conditions that prevail in the years ahead.

Supply from Frontier Areas

We accept, as do submittors, that the Canadian frontier regions have the geological potential to supply a substantial portion of the nation's future crude oil needs. The proportion of Canada's total crude oil supply that may ultimately be produced from the frontier regions will, however, depend on exploration success, prevailing economic conditions and technological progress in the development of appropriate production and transportation systems.

Reserves potential is recognized in three frontier areas currently being explored; the Beaufort Sea – Mackenzie Delta, the Arctic Islands, and the East Coast offshore region. To date there has been no production from any of these areas.

The Hibernia field, east of Newfoundland has been the most significant frontier oil discovery. To date ten wells have been drilled in the field. However, there has been no proposal for development, production and transportation of the oil, so that considerable uncertainty surrounds reserves. Our studies support a general consensus that recoverable reserves will be in the order of 160 million cubic metres, assuming enhanced oil recovery mechanisms in place.

Potentially producible reservoirs have been discovered in the general Hibernia area, in the onshore Mackenzie Delta, the Beaufort Sea and in the Arctic Islands. These reservoirs are modest in size, and in the case of those offshore, it appears that specially designed low cost production systems will have to be developed if economically viable production is to be attainable. To assess the full potential for commercial production in the frontier areas will require continued exploration and development activity.

We assume that production from the Hibernia area will commence in 1993, and reserves in the order of 200 million cubic metres will have been established. For our economic assessments we assume that production will be by means of two platforms brought on over a two-year period. In the case of the Beaufort Sea region, we assume that production will commence from the on shore and near shore reservoirs at about the same time.

Oil development in the Arctic Islands is at such an early stage that it is impossible to speculate with any degree of confidence when significant production levels might be achieved. Panarctic envisages a project to move oil by tanker from the Bent Horn pool on Cameron Island as early as next year, however, quantities are modest, some 60 000 cubic metres annually.

Submittors' estimates of frontier reserves are shown in Table 7-9. Included in this table for purpose of comparison are estimates of discovered resources[1] from the COGLA 1983 Annual Report.

We recognize that our forecast of oil supply from the frontier areas is speculative. Corresponding forecasts from submittors differed widely and covered a range from zero to about 200 000 thousand cubic metres per day in 2005. We feel that a range of zero to about

[1] Discovered resources are estimates of the quantities of crude oil or natural gas occurring in known reservoirs but of uncertain economic viability.

Table 7-9
Remaining Reserves and/or Discovered Resources of Crude Oil Frontier Regions

(Million Cubic Metres)

	Mackenzie-Beaufort	Arctic Islands	East Coast Offshore
COGLA[1]	133.0	76.1	225.2
CPA	—	—	175.0[2]
Dome	400-480	76.0	225.0
Gulf	158.9	127.2	476.7
Panarctic		68.3	
Petro-Canada		65.8	316.4
NEB	—	—	160[2]

[1] Discovered resources
[2] Hibernia only

100 000 cubic metres per day is perhaps more realistic. We believe the degree of success achieved in developing production from frontier regions will also be an important factor in determining how rapidly synthetic projects proceed.

Total Crude Oil and Equivalent

Submittors' estimates of total supply of crude oil and equivalent, summarized in Appendix 7, Table A7-14, range in 2005 from 110 000 to 270 000 cubic metres per day, except for Dome's high price cases. A wide range of underlying assumptions is involved. In general, estimates at the low end of the range are based on low world oil prices and unfavourable fiscal regimes. The high end of the range reflects more optimistic views of future taxation policies and higher world oil prices. Submittors' estimates are compared with our forecast in Figure 7-5. Our plausible range is also shown on this figure. It can be seen from this figure that the submittors' estimates generally fall within our range of uncertainty, only Dome's two highest cases are significantly beyond this range.

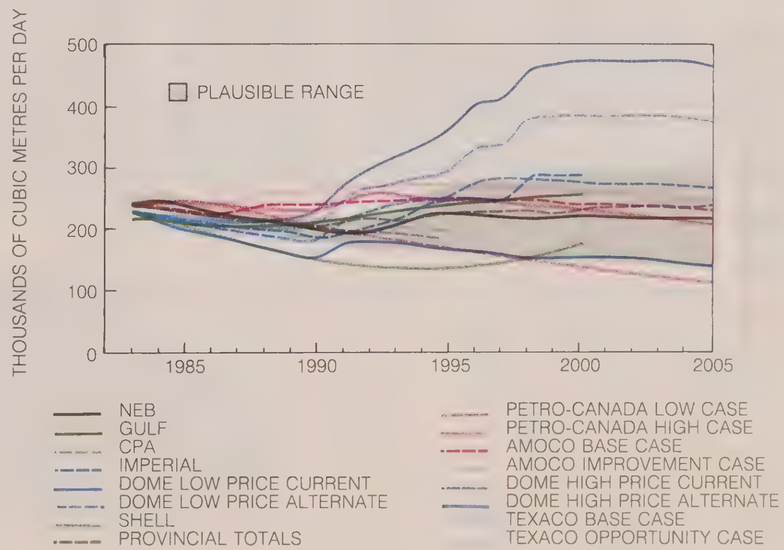
For the middle and late 1980s our Reference Case forecast is in the order of ten percent greater than the forecast in the 1981 NEB Report. This results from the fact that some pools have been performing better than previously expected, and actual production has been less than productive capacity since 1980, leaving oil supplies available to be produced at a later date. In addition, government programs have encouraged the maintenance of production levels from existing wells and have promoted infill drilling of existing pools.

Over the past two years, improvements in productive capacity have been such that total productive capacity has been maintained at a fairly constant level. Our discussions with industry indicated that total productive capacity from conventional sources could be sustained at this level for an additional year or two, after which it is expected to decline at a more traditional rate.

7.2 Primary Demand for Oil

In addition to end use requirements, primary oil demand includes oil for electricity generation, steam production and refinery own use. We also include liquefied petroleum gases (LPG) produced in refineries in primary oil demand. Figure 7-6 illustrates the composition of primary oil demand (refer to Appendix 10 Table A10-1 for levels). Primary demand for oil could grow at about 0.5 percent per year between 1983 and 2005, or it could decline at about 0.7 percent over the same period. Thus, oil demand in 2005 could be from 14 percent lower to 17 percent higher than demand in the Reference Case. This range is somewhat wider than that for other fuels as a result of the uncertainty surrounding future im-

Figure 7-5
Projections of Productive Capacity of Crude Oil, and Equivalent
Canada



Source: Table A7-14, Appendix 7

Table 7-10
Distribution of Primary Oil Demand by Product

(Percent)

	1973	1983	1990	2005
Aviation Fuels	3	5	5	7
Motor Gasoline	30	38	36	33
Light Fuel Oil & Kerosene	21	12	8	5
Diesel Fuel Oil	11	18	22	27
Heavy Fuel Oil	22	12	13	10
Asphalt	4	4	4	5
Other	9	11	12	13
Total	100	100	100	100

provements in vehicle fuel efficiencies. Our projection of primary demand for oil is compared to those of submittors in Appendix 7.

Our views on end use demand for oil follow from our conclusions about transportation requirements (Chapter 3) and interfuel competition in residential, commercial and industrial uses (Chapter 4). Oil demand has declined significantly since 1978 as consumers responded to the rapid escalation of domestic oil prices, to off oil programs of the federal government and to government conservation initiatives. More recently, the 1982 recession contributed to the sharp drop in demand.

We project demand to continue to decline throughout the 1980s. The rate of decline moderates as time goes on as a result of more limited substitution possibilities in non-transportation uses. Moreover, oil use in transportation gradually recovers as the impact of growing vehicle fleets overtakes reduced improvements in fuel efficiencies.

Our projections of demand for refined petroleum products imply a significant shift from gasoline to diesel fuel as shown in Table 7-10.

This shift results because we assume that:

- increasing dieselization of medium and heavy trucks will occur to improve payload efficiency;
- growth in intercity freight transport will be more rapid in the rest of the 1980s than it has recently been; and
- there will be a significant decline in motor gasoline demand associated with substantial improvements in the efficiency of the car stock.

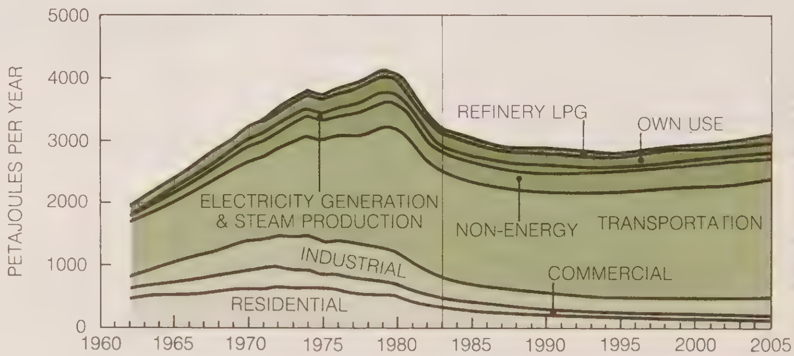
Regional primary oil demand by product is shown in Table A7-33. Submittors' projections of oil product demand at the end use level are compared in Figure 7-7.

7.3 Requirements for Refinery Feedstock

Refinery feedstock requirements differ from end use petroleum product demand by the amount of refinery fuel and conversion losses, and petroleum product imports and exports.

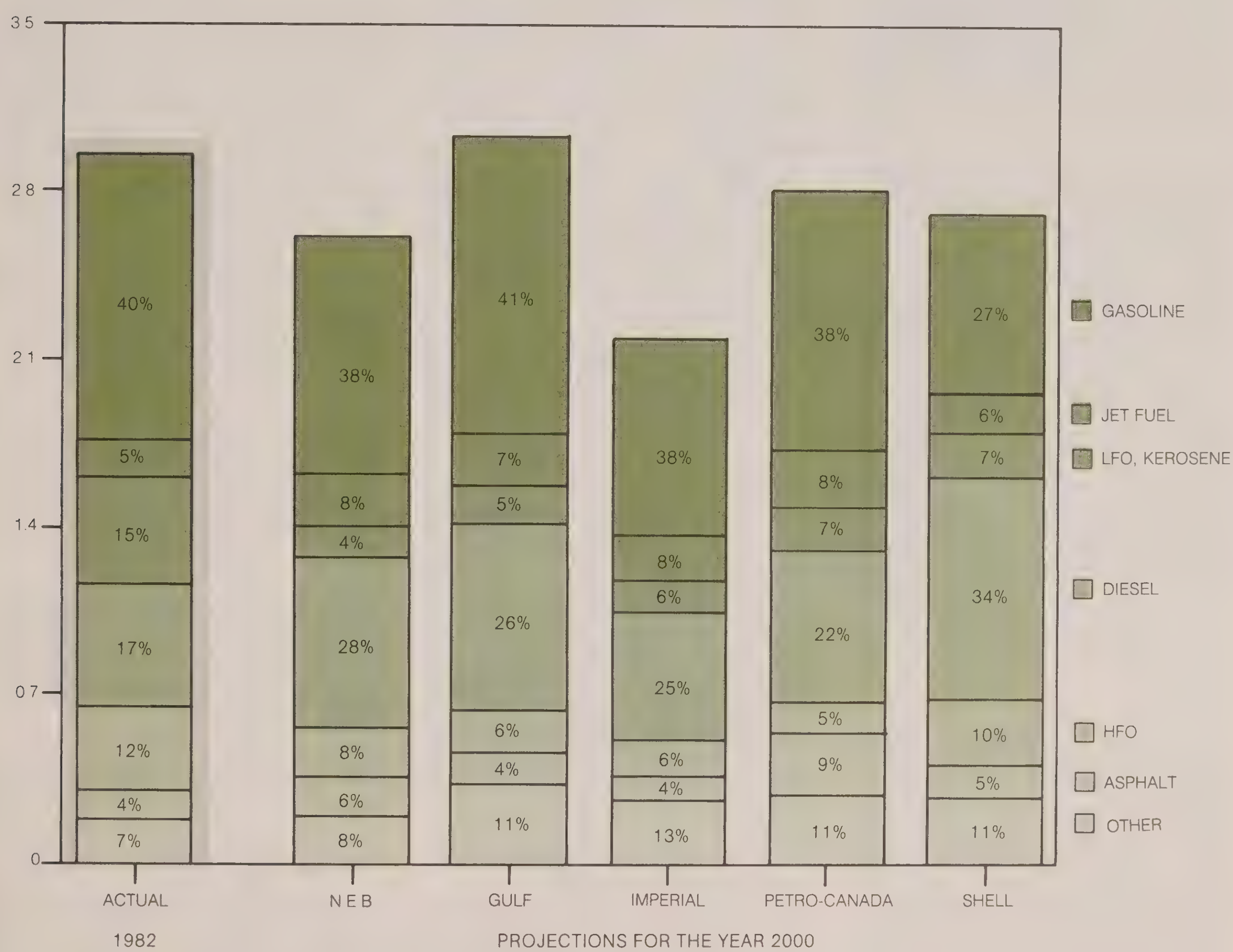
Estimation of the future need by refineries for feedstock has become

Figure 7-6
Primary Demand for Oil, Canada



Source: Table A7-34, Appendix 7
Table A10-2, Appendix 10

Figure 7-7
Projections of End Use[1] Oil Product Demand, Canada (Exajoules)



Source: Table A7-34 Appendix 7
(1) Excludes thermal generation, steam production and refinery own use.

complicated by the ongoing contraction and reorganization of the refining industry brought about by low demand for refined petroleum products. In this section, we outline the methods used and assumptions employed to estimate the demand for light and heavy crude oil, given our projections of petroleum product demand.

The impact of recent declines in demand on the Canadian refining sector has been severe. In 1983 alone, seven refineries were taken permanently out of service and at others the processing capacity was reduced. The total reduction in capacity amounted to some 39 000 cubic metres per day, most of which took place in Eastern Canada. Further closures are scheduled in 1984. At the same time as refining capacity is being shut down, a few new plants and processing units the construction of which was decided upon at a time of buoyant demand, will be coming on stream in the next year or so; their inauguration will merely hasten the abandonment of older, less efficient capacity.

Aside from reductions in crude distillation capacity, considerable adjustments have been made to refinery configurations in response to shifts in the relative importance of individual product demands, and in the relative availabilities and costs of different qualities and types of crude oil and other feedstocks. The expectation of a substantial surplus of heavy fuel oil has produced a number of upgrading modifications to existing refineries at locations across the country. Progressive adaptations of this character are to be anticipated.

In a number of cases, the marketing areas supplied by individual refineries have undergone radical change, as increasing use of new and surviving plant has supplanted the operations of other refineries. In some cases this has resulted in extensive rationalization of supply lines involving large scale intercompany refined product exchanges, purchase-sale arrangements and crude oil processing arrangements. In Ontario and Quebec, one or two refineries now generally serve where two or three were previously needed.

Table 7-11
Refinery Feedstock Requirements

(Thousands of Cubic Metres per Day)

	1983	1990	2005
Total Feedstock Requirements	232	198	218
Heavy Crude	11	18	23
Gas Plant Butanes and Other	6	5	5
Inventory Drawdown	2	–	–
Remainder–Requirements for Domestic Light and Imports	213	175	190

Source: Table A7-35, Appendix 7

Our forecast of feedstock requirements is shown in Table 7-11.

The method we have adopted is to estimate the total requirements for feedstock, then estimate heavy crude oil requirements. The net of total requirements and heavy crude oil requirements is the requirement for domestic light crude oil and equivalent feedstock and imports.

Total refinery feedstock requirements estimated for the different regions of Canada were developed from the corresponding estimates of demand for petroleum products (Section 7.2). The process took into account the actual and potential degree of flexibility in refining, product yields, likely needs for inter-regional transfers and inventory levels, as well as anticipated levels of imports and exports of petroleum products.

Key assumptions concerning these factors are as follows:

- It was assumed that in the longer term the necessary refinery investments would be made to permit refinery yields to correspond with product demand. As a result of off oil measures and the availability of low cost electricity, demand for heating oil has been declining and is forecast to continue to do so. At the same time we project an increase in the demand for diesel fuel. This could pose problems for some refiners in meeting middle distillate demand which is comprised of these two products. By the year 2000 we project diesel fuel demand to be over 80 percent of middle distillate demand compared to 50 percent now. These changes

could no doubt be accommodated with further upgrading of refinery processes and some relaxation of manufacturers' specifications of fuel quality. Refinery upgrading could be delayed or avoided if balances in required product output were achieved by imports of diesel fuel and/or exports of heating oil.

- Interregional transfers were estimated taking into account present and planned refinery capacity. The most likely sustained transfer is from the Prairies into British Columbia.
- Inventory levels have been adjusted through the forecast period such that a constant number of days supply would be held.
- Petroleum product imports and exports consist mainly of imports of heavy fuel oil into the Atlantic region and exports of heavy fuel oil from Ontario and the Prairies.

On the basis of the refined product demand outlook in the Reference Case, it is estimated that total crude oil and equivalent required by Canadian refineries will fall from 232 000 cubic metres per day in 1983 to about 198 000 cubic metres per day in 1990, increasing thereafter to 218 000 cubic metres per day in 2005.

The outlook is somewhat different in Western Canada (the Prairie provinces and British Columbia) from that in the rest of the country. In Ontario, Quebec and the Altantic region, the decline in crude oil demand continues through 1990 and recovers slowly thereafter, leaving it well below 1983-84 levels even by 2005. In Western Canada recovery of demand is expected to be relatively more rapid and the 2005 level exceeds that of 1983. This regional difference, arising basically from differences in the growth of product demand, could be emphasized if refiners preferentially manufacture petroleum products in Edmonton and expand the area supplied from there.

The heavy crude oil requirement, apart from upgrading requirements, has been taken as a function of asphalt needs to meet both domestic and export demands. A heavy crude/asphalt production ratio of 2.4/1 has been assumed. An increase is foreseen in demand for domestic heavy crude from 11 300 cubic metres per day in 1983 to 17 800 cubic metres per day in 1990 and 22 600 cubic metres per day in 2005. The matter of field upgrading, basic to the ultimate use in Canada of heavy crude oil, is discussed in Section 7.1.

Some gas plant butanes are also used as refinery feedstock and reduce the total volume of crude oil required by refineries.

The upper and lower bounds of the range of product demand were also converted into corresponding estimates of crude oil requirements using similar assumptions and methodology as in the Reference Case. The high product demand yields feedstock requirements of 212 000 cubic metres per day in 1990, rising thereafter to 249 000 cubic metres per day in 2005, a modest 0.6 percent average annual increase over the forecast period. Feedstock requirements could be as low as 190 000 cubic metres per day in 2005 with low product demand.

In the Atlantic region, excess distillation capacity will remain during the forecast period unless further closures take place. The excess could be reduced if refineries were able to negotiate imported crude oil processing agreements for the export market or to make larger product exports than those envisaged.

In Quebec and Ontario, refiners are expected to try to maximize capacity utilization and cost effectiveness by either intercompany crude oil processing or purchase – sales arrangements.

It appears that there will also be surplus refining plant in Western Canada which could be taken out of service in the future. As noted above, some refiners in the Prairie provinces will probably operate at or near capacity and transfer products to British Columbia in the late 1980s. The estimated surplus distillation capacity in the 1990s could be in the order of 30 000 cubic metres per day.

7.4 Supply/Demand Balances

As in previous sections dealing with supply and requirements, it is useful to discuss balances in terms of light and heavy crude oil separately. A comparison of total crude oil supply and requirements illustrates Canada's net oil self-sufficiency. The individual balances, however, provide background to the specifics of Canada's trade in oil and the logistics of moving oil to markets. The capabilities of Canadian refineries to use light and heavy crude oil and the supply relative to those capabilities are significantly different.

Light Crude Oil

Figure 7-8 illustrates the supply and demand balance for light crude oil. The supply includes synthetic oil production and the projected output from upgrading plants processing heavy crude and bitumen. The figure indicates a persistent excess of demand over indigenous supply of up to 33 000 cubic metres per day, except for a short period immediately following the introduction of frontier production in 1993. The difference between total supply and total demand represents the implied net import requirement for light crude oil.

In common with other aspects of Canada's energy economy, the situation with regard to imports of crude oil has undergone radical change over the past few years. For a lengthy period starting in the early 1960s, imported oil has been progressively displaced by domestic supplies from Western Cana-

Table 7-12
Light Crude Oil and Equivalent Supply and Demand Balance

(Thousands of Cubic Metres per Day)

	1983	1990	2005
Domestic Producibility	188	162	157
Minimum Imports	35	26	32
Total Supply	223	188	189
Total Domestic Requirements	213	175	190
Excess Supply	10	13	—

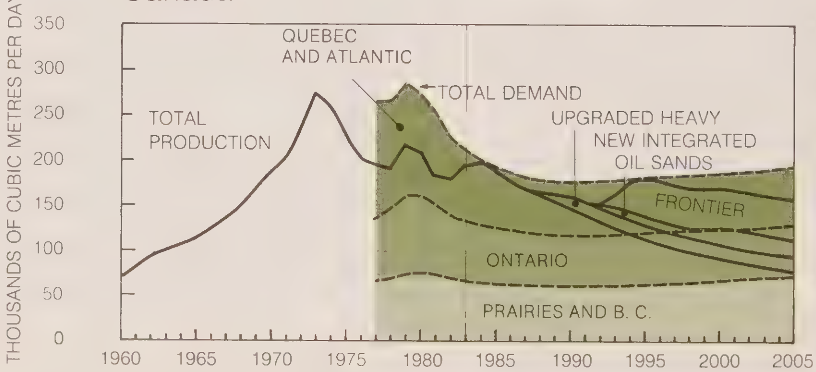
Source: Table A7-35, Appendix 7

da, extending the market limits of the latter further eastward until in 1983 Western Canadian oil supplied a significant proportion of refinery needs in Quebec and the Atlantic provinces. A major factor in this change has been government encouragement of development of the domestic oil industry.

Since imports are essentially a balancing item varying widely with shifts in overall demand, in corporate and government commitments and in Canadian crude oil availability, fluctuations in their magnitudes are foreseen in the years ahead. It was assumed that the Portland-Montreal pipeline would be kept in operation, requiring a minimum throughput of 8000 cubic metres per day and that the federal transportation subsidy for Western Canadian oil sent to the Atlantic region would be maintained throughout the period. Table 7-12 shows our forecast of light crude oil trade for 1983, 1990, and 2005. The minimum imports shown in this table are at times in excess of the difference between domestic supply and domestic requirements reflecting the above considerations.

The phenomenon of continued declining producibility of light crudes relative to heavy is not confined to Canada but is seen almost world-wide. The Eastern Canadian import requirements have been seen as essentially for light crudes; this may pose problems of cost or availability from foreign sources and could influence future refinery configurations.

Figure 7-8
Supply and Demand Light Crude Oil Canada



Source: Tables A7-1, A7-3 and A7-35, Appendix 7

Exports of light and medium crude oil from Canada could possibly continue through 1990 (Reference Case) since supply, with minimum desirable imports included, is anticipated to be in excess of Canadian demand until then. Even with high product demand, excess available volumes are foreseen through 1988.

The geographic source of frontier production is relevant, as it affects the operation of the Interprovincial pipeline system. Currently, this system transports oil from the Prairie provinces east as far as Montreal. Should all frontier supplies come from the east coast, the Sarnia to Montreal part of this system might have to be reversed to meet Ontario demand. It is not clear whether such a reversal would in turn prevent the flow of domestic heavy crude oil to Montreal and if so reduce Canada's flexibility in marketing that commodity. In our forecast we have assumed that about 30 percent of frontier supply would come from the Mackenzie Delta – Beaufort Sea area through a pipeline

to Alberta. This, in combination with the projected supply from two heavy crude oil upgraders and two medium size oil sands plants provide approximate minimum quantities required to maintain sufficient supply from Western sources to preclude a need for the pipeline reversal.

Heavy Crude Oil

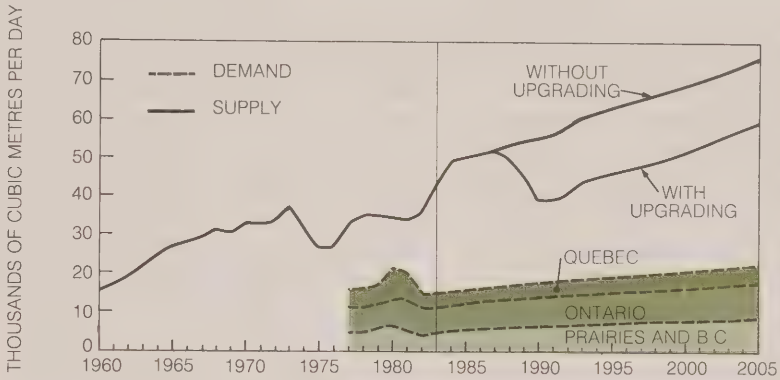
Figure 7-9 illustrates the supply and demand balance for heavy crude oil. Part of the heavy crude oil stream consists of pentanes plus, a diluent that is added to reduce the viscosity of the heavy crude oil so that it can be transported by pipeline. Supply is forecast to increase at a somewhat faster rate than Canadian refinery demand. The outlook is for continued volumes at a rate of 25 000 to 35 000 cubic metres a day to be available for export.

As shown in the figure the volume of heavy crude oil available could be affected by the outcome of plans now in place to install upgrading facilities in Western Canada. United States demand for Canadian heavy crudes has been strong for several years; while this remains so, the incentive for commitment to upgrading projects either in the field or at refineries will be all the more dependent on the margins available in Canada to producers and refiners.

Of continuing concern is the availability of sufficient diluent for movement of all potential heavy crude oil production. The projected construction of an upgrader at Lloydminster could alleviate this concern; diluents could as well be produced from the processing of Western light crude oil.

We have not considered the implications of increased eastward movement of heavy crude oil on pipeline capacity.

Figure 7-9
Indigenous Heavy Crude Oil Supply and Demand Canada

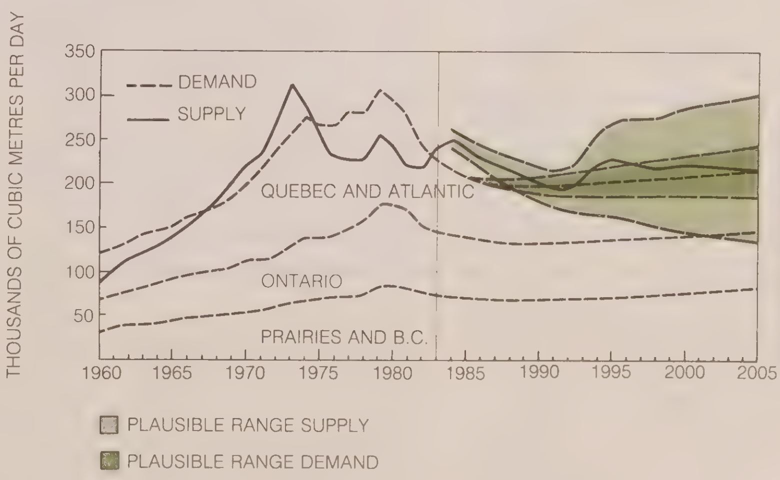


Source: Tables A7-1, A7-3 and A7-35, Appendix 7

Total Crude Oil and Equivalent

Both supply of and demand for total crude oil could vary significantly from our reference projection. Figure 7-10 shows what we consider to be a plausible range for both supply and demand. In general, it is indicated that there are reasonable prospects for Canada to be self-sufficient in oil on a total basis. This will depend mainly on the availability of frontier supplies and the extent of oil sands development. The balance depends to a somewhat lesser extent on variations in demand.

Figure 7-10
Supply and Demand Total Crude Oil and Equivalent Canada



Source: Tables A7-1, A7-3 and A7-35, Appendix 7

CHAPTER 8

NATURAL GAS LIQUIDS

8.1 Supply of Natural Gas Liquids

Natural gas liquids (NGL), which consist of ethane, propane, butanes and pentanes plus, are by-products of the processing of natural gas and the refining of crude oil. Accordingly, quantities produced are dependent on the quantity and composition of natural gas production and on the quantity and quality of crude oil that is refined. In addition, production is dependent on the capability of a gas processing plant or refinery to recover NGL, and on the process units in a refinery. These factors are discussed in this section with reference to supply from gas plants, refineries, synthetic crude oil and upgrading plants and frontiers. In our forecast, we assume that, except for some potential supplies from the Venture project in the Sable Island area, only gas processing plants in conventional producing areas and refineries will contribute to the supply of NGL during the forecast period. Historical production of NGL is outlined in Appendix 8, Table A8-1 and our forecast of NGL production is summarized in Appendix 8, Table A8-2. Submittors' forecasts are shown in Appendix 8, Tables A8-3 to A8-8.

Supply from Gas Plants

The forecast of NGL production from natural gas processing and reprocessing plants in the conventional producing areas is based on the natural gas production forecast discussed in Chapter 6 and summarized on Figure 6-13. For purposes of the NGL forecast, however, it has been assumed that gas production will decline less precipitously after 1990 than required by the expiry dates now applicable to existing export authorizations. Natural gas production increases in the near term and then, as modified, declines gradually until 2002 when exports cease. After 2002, growth in Canadian demand results in increases in natural gas production through to the end of the forecast period, at which time the production from Western Canada is forecast to be 19 percent higher than the 1983 level.

The projected NGL production from gas plants tends to track natural gas production with, except for ethane, yields per unit of gas production continuously declining throughout the forecast period. The declining yields reflect reduced content of these liquids in the gas stream. This results from reduced production of solution gas (gas which is in solution with crude oil in the reservoir and is produced with the crude oil) and the termination of gas cycling schemes (schemes in which part or all of the produced natural gas is reinjected into the reservoir after removal of NGL in a gas processing plant in order to maximize NGL recovery from the reservoir) both of which yield higher than average quantities of liquids per unit of gas production. Submittors agreed that production from future conventional supplies of natural gas will yield less of the liquids heavier than ethane than is obtained from current production. Ethane is unique in that only about one-third of the quantity in produced gas is currently being extracted. Over the projection period this proportion will increase as demand increases. The ethane content of future supplies of natural gas is expected to be the same as that of current production.

A comparison of the current average yields of propane, butanes and pentanes plus from natural gas production in Alberta and those assumed in our forecast from reserves additions and uncommitted natural gas is shown in Table 8-1.

Detailed plant by plant forecasts of NGL production are provided in Appendix 8, Tables A8-9 to A8-12. It is assumed that additional field plant capacity for extraction of ethane will be put in place in Alberta and that, as has been proposed for British Columbia, a straddle plant (natural gas reprocessing plant on a main gas transmission pipeline) will be built in 1985, which will recover propane, butanes and pentanes plus only.

Ethane production from gas plants in conventional areas is forecast to more than double by 1990 as can be seen in Table 8-2. This results from the installation of new field plant extraction facilities and from the processing of larger volumes of natural gas at existing straddle plant facilities. Submittors' forecasts of ethane production ranged from 16 300 cubic metres per day to 31 600 cubic metres per day in 1990, reflecting different assumptions about both supply and demand. Our forecasts of propane, butanes and pentanes plus production from gas plants, which for most years lie within the range of submittors' estimates, tend to be higher than most submittors in 1990. This results from differing assumptions with respect to yields, differences in levels assumed for gas production, the inclusion of estimates of NGL in mixes in our estimates, and the assumption that a straddle plant will be built in British Columbia.

Table 8-1
Cubic Metres NGL Per Million Cubic Metres
Raw Natural Gas Production

	Alberta 1983 Average	NEB Forecast from Reserves Additions and Uncommitted Natural Gas
Propane	57	46
Butanes	35	26
Pentanes Plus	59	42

Table 8-2
Sources of NGL Production

	1983 PJ[1]	1983 $10^3m^3/d$[2]	1990 PJ	1990 $10^3m^3/d$	2005 PJ	2005 $10^3m^3/d$
GasPlants						
Ethane	91	13.5	187	27.9	118	17.6
Propane	142	15.2	197	21.1	130	13.9
Butanes	99	9.5	132	12.6	84	8.0
Pentanes Plus	194	15.1	225	17.5	139	10.8
Refineries						
Ethane	—	—	—	—	—	—
Propane	33	3.5	29	3.1	32	3.4
Butanes	27	2.6	23	2.2	25	2.4
Pentanes Plus	—	—	—	—	—	—
Frontier						
Ethane	—	—	—	—	—	—
Propane	—	—	12	1.3	12	1.3
Butanes	—	—	8	0.8	8	0.8
Pentanes Plus	—		24	1.9	24	1.9
Total						
Ethane	91	13.5	187	27.9	118	17.6
Propane	174	18.7	238	25.5	173	18.6
Butanes	126	12.1	163	15.6	117	11.2
Pentanes Plus	194	15.1	249	19.4	163	12.7

(1) Petajoules per year.
(2) Thousands of cubic metres per day.

Source Tables A8-9 to A8-14, Appendix 8.

There are many factors that could lead either to increases or decreases in these projections. The most obvious is a variance in the assumed natural gas production forecast, resulting from changes in Canadian or export demand. In general, a change in natural gas production would result in a change only half as large in NGL production. This is because the gas that would be most affected by these changes would be non-associated gas (natural gas not in contact with crude oil in a reservoir), which on average has a lower yield of gas liquids.

Changes in light crude oil production would result in changes in the quantity of solution gas production which is generally rich in gas liquids. In this case, the difference in NGL production would be about twice the difference in gas production.

Changes in the volumes of natural gas exports or demand for natural gas east of Alberta would result in proportional changes in the production of ethane, over 75 percent of which is currently produced at gas reprocessing plants on the main gas transmission lines leaving Alberta.

NGL production from reserves additions of natural gas could also vary from our forecast depending on what the actual NGL content of reserves additions of natural gas turns out to be.

Almost all of the natural gas liquids heavier than ethane are currently being recovered, however, there is additional potential for recovery of ethane. Ethane recovery facilities added at straddle plants over the last few years and those planned for completion in 1984, and planned increased field plant extraction of ethane will greatly increase the volume of ethane recovered in Alberta.

Supply from Refineries

The forecasts of propane and butanes production from refineries are based on the forecast of crude oil feedstock requirements discussed in Chapter 7 and shown in Appendix 7, Table A7-34. Refinery crude oil throughputs are forecast to decline gradually to about 86 percent of current levels by 1990 and then increase for the remainder of the forecast period so that by 2005 they will be about 95 percent of 1983 levels. The yields of propane and butanes per unit of crude runs are assumed to remain at the 1983 levels in each region during the forecast period.

These yields could change as a result of changes in the products refineries are required to make, changes in the quantity and quality of crude used by refineries, new refineries coming on stream, and refinery closures. It is difficult to estimate the combined effects of these changes and for the purposes of our propane and butanes production forecast they are ignored.

Forecasts of refinery propane and butanes production are given by region in Appendix 8, Tables A8-13 and A8-14, respectively. Submittors' forecasts are summarized in Appendix 8, Tables A8-7 and A8-8.

In 1990, as can be seen in Table 8-2, propane and butanes production from refineries is forecast to be about 90 percent of current levels. Submittors'

forecasts of 1990 production ranged from a decrease of 20 percent to an increase of about 50 percent over 1983 levels.

Supply from Synthetic Crude Oil Plants and Upgraders

Our supply forecast does not include any production of NGL from synthetic crude oil plants or heavy crude oil upgraders. Current indications are that the economics of recovering NGL from the gases produced at synthetic crude oil plants are very marginal. Amoco estimated that 1575 cubic metres par day of propane and 315 cubic metres per day of butanes could be recovered from the Suncor and Syncrude plants. Discussions with other submittors supported these numbers in total but indicated that the potential supply of propane might be somewhat lower, and that of butanes higher. A potential supply of about 1500 cubic metres per day of ethane from the Syncrude plant was also identified in discussions with submittors.

In addition to these plants, the new synthetic crude oil plants and heavy oil upgraders that have been included in our oil supply forecast are potential sources of NGL, although with newer upgrading techniques, fewer by-products may be available than from existing plants. Dome forecast that in its low price case, synthetic crude oil plants would not contribute to the supply of propane, but in the high price case synthetic crude oil plants would supply 3310 cubic metres per day of propane and 300 cubic metres per day of butanes in 1990, and 6310 cubic metres per day of propane and 575 cubic metres per day of butanes by 2005.

Supply from Frontiers

We have included in our projection NGL from natural gas production on the Scotian Shelf. We assume that only propane, butanes and pentanes plus will be recovered from this gas, although it is evident that if markets for ethane were to materialize, ethane extraction facilities could be added. Production is forecast to begin in 1990 at the volumes shown in Table 8-2.

We have assumed that gas production in the Mackenzie Delta-Beaufort Sea region will not contribute to the supply of NGL during the forecast period. There is a potential for some NGL recovery from this gas. If recovery occurred at the site of natural gas production, a transportation system would be required to move these liquids to markets. There is also a possibility that this gas could be processed in existing facilities in Western Canada. Imperial forecast that, based on Mackenzie Delta-Beaufort Sea gas production of 297 petajoules per year in 1996, 2400, 900 and 500 cubic metres per day of ethane, propane, and butanes, respectively, could be produced.

With regard to production of solution gas associated with frontier oil production, it is assumed that any NGL associated with this gas would be reinjected along with as much of the gas as is possible, as part of a scheme to maintain reservoir pressure and increase oil recovery. Any pentanes plus production is likely to be brought to markets in the crude oil stream.

8.2 Demand for Natural Gas Liquids

Demand for NGL consists of the end use demand for ethane, propane and butanes discussed previously, as well as use for gasoline blending, refinery feedstocks and hydrocarbon miscible projects. Table 8-3 summarizes our outlook on demand.

Table 8-3
Demand for Natural Gas Liquids[1]

	1983		1990		2005	
	PJ[2]	$10^3m^3/d$[3]	PJ	$10^3m^3/d$	PJ	$10^3m^3/d$
End Use						
Ethane	35	5.2	75	11.2	115	17.2
Propane	82	8.8	101	10.8	133	14.3
Butanes	8	0.8	39	3.7	40	3.8
Refinery Feedstock and Gasoline Blending						
Butanes	37	3.6	32	3.1	35	3.4
Miscible Floods						
Ethane	5	0.7	84	12.5	—	—
Propane	17	1.8	78	8.4	—	—
Butanes	9	0.9	28	2.7	—	—
Total						
Ethane	40	5.9	159	23.7	115	17.2
Propane	99	10.5	179	19.2	133	14.3
Butanes	55	5.2	100	9.5	75	7.2

(1) Net of own use for fuel.
(2) Petajoules per year.
(3) Thousands of cubic metres per day.

Source: Table A8-16, Appendix 8.

End Use

Ethane is used extensively in the petrochemical industry. Significant increases in demand are projected as a result of the start up of an additional ethane-based ethylene plant in Alberta in 1984. A second ethylene plant is assumed to commence operation in the mid 1990s (Chapter 3). Modest growth in the demand for propane is projected, influenced, particularly in the period to 1990, by anticipated conversion of taxis and other commercial auto fleets from gasoline. Substantial growth in demand for butanes is projected in the same period, resulting from our assumption that the Eastern Canada based petrochemical industry would partially convert away from the use of crude oil as a feedstock. Pentanes plus is treated as a crude oil equivalent and discussed in Chapter 7.

Refinery Feedstocks and Gasoline Blending

Feedstocks to refinery process units and butanes used for blending in gasoline currently account for over 80 percent of the demand for butanes in Canada (excluding demand for miscible floods). This demand is forecast to decrease by about five percent from 3600 cubic metres per day in 1983 to 3400 cubic metres per day in 2005.

Miscible Fluids

Our forecasts of net requirements (after accounting for reproduced fluids from hydrocarbon miscible projects) for ethane, propane and butanes for hydrocarbon miscible projects are outlined in Appendix 8, Tables A8-18 to A8-20, respectively. These forecasts are based on existing hydrocarbon miscible projects and on our forecast of reserves additions from miscible projects in Appendix 7, Table A7-6.

It is assumed that, on average, 1.5 cubic metres of NGL will be injected per cubic metre of reserves additions of oil from hydrocarbon miscible projects. The NGL is assumed to be injected over a period of 10 years beginning in the year after the reserves are booked, with two-thirds of the injected volumes being recovered over 15 years, beginning in the sixth year following the start of injection. The breakdown of all NGL used is estimated to be 55 percent ethane, 35 percent propane and 10 percent butanes. Adjustments were made to account for knowledge of NGL requirements for existing or planned projects.

Ethane and propane are expected to be the preferred injection fluids, with butanes generally only being injected where they are already part of an NGL mix.

·From the year 2000 until the end of the forecast period, as can be seen in Figures 8-1 to 8-3, there is no net requirement for miscible fluids.

Our forecast of miscible fluid requirements could be high to the extent that carbon dioxide is used instead of NGL in miscible floods. Substitution of carbon dioxide is technically feasible in most reservoirs. Several submittors indicated that after 1990 there would be a shift from the use of NGL to carbon dioxide. This would depend on the economics and availability of carbon dioxide compared to NGL.

Natural Gas Liquids Exports

The approved natural gas liquids export licences as of 1 January 1984 are shown in Appendix 8, Table A8-15. In addition, the Board authorizes, under semi-annual and quarterly orders, the export of propane that it deems to be surplus after allowance is made for Canadian requirements and previously licensed exports. The Board also authorizes the export of unrestricted volumes of butanes.

8.3 Supply/Demand Balances

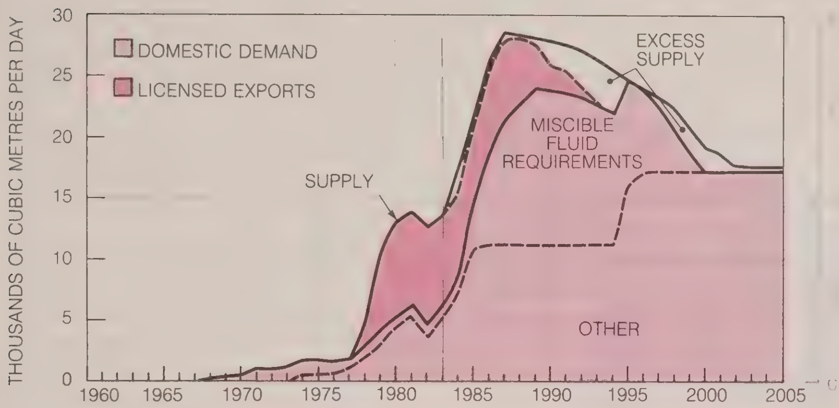
With the exception of pentanes plus, which is discussed in Chapter 7, it is our view, as well as that of submittors, that the potential supply of NGL will exceed domestic requirements plus licensed exports throughout the forecast period. The historical and forecast supply/demand picture for ethane, propane and butanes is shown in Figures 8-1 through 8-3, respectively. It should be noted that the forecast supply of propane and butanes in these figures includes some production from Scotian Shelf natural gas which could not be used (economically) to meet demands in Western Canada. The forecast portion of the supply/demand balances is detailed in Appendix 8, Tables A8-18 through A8-20.

In the near term, increased recovery of ethane is expected to meet the increase in requirements for ethane in miscible floods. In the long term, reduced net demand for ethane for miscible projects resulting mainly from the production of previously injected ethane is offset somewhat by increased feedstock requirements for a third ethylene plant that is forecast to come on stream in 1995.

Figure 8-1 shows ethane production in excess of demand. If no export market is available, it is anticipated that supply would adjust to domestic demand so that excess volumes would either not be produced or would be reinjected into the sales gas streams.

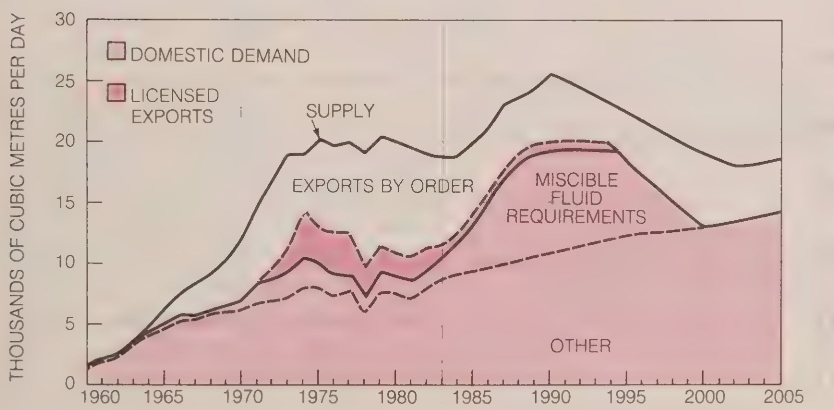
By the end of the forecast period, demand for propane in the commercial sector is projected to more than double and in the transportation sector to increase to more than six times the current level. These demands as well as the increased demand for propane for miscible floods are expected to be met throughout the forecast period. All propane in excess of domestic demand is likely to be exported. By 1990, the per-

Figure 8-1
Ethane Supply and Demand, Canada



Source: Table A8-1, Appendix 8
Table A8-18, Appendix 8

Figure 8-2
Propane Supply and Demand, Canada

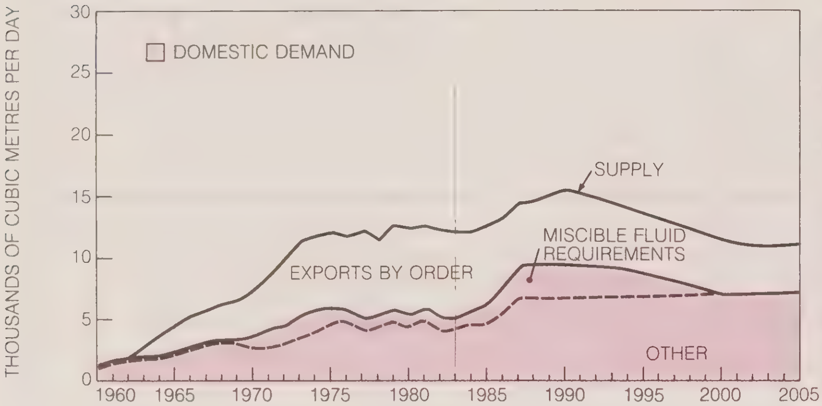


Source: Table A8-1, Appendix 8
Table A8-19, Appendix 8

centage of propane production that goes to export is expected to decrease to about 25 percent of total production compared to 43 percent in 1983. Absolute volumes that go to export by 1990 are forecast to be about 77 percent of the 1983 level of 8040 cubic metres per day.

Demand for butanes, which in the petrochemical sector increases over five-fold during the forecast period, is expected to be met throughout the forecast period. As is the case for propane, butanes in excess of domestic demand are likely to be exported. By 1990, the percentage of butanes production going to export is expected to be about 39 percent of total production compared to 57 percent in 1983. Absolute volumes that go to export are forecast to be about 90 percent of the 1983 level of 6230 cubic metres per day.

Figure 8-3
Butanes Supply and Demand, Canada



Source: Table A8-1, Appendix 8
Table A8-20, Appendix 8

CHAPTER 9

COAL

9.1 Supply of Energy from Coal

For a long period, coal was the main source of energy in Canada. In 1950, coal production was about 18 megatonnes. With the discovery of large reserves of oil and natural gas in the 1950s and the subsequent conversion of locomotives to diesel power, production fell to 10 megatonnes by 1960. Interest in Canadian coal began to revive late in the 1960s and the rapid escalation of world oil prices after 1973 enhanced the competitive position of the Canadian coal industry. Increased use of Western coal in Ontario and expansion of export markets made Canada a net coal exporter for the first time in 1981. These developments increased the share of coal in Canada's total energy production and by 1982, coal production was 43 megatonnes, equivalent to 1030 petajoules or ten percent of total primary energy production. In the same year Canadian domestic demand of 1000 petajoules was about ten percent of total primary energy consumption. Table A9-1 in Appendix 9 provides a historical overview of Canadian coal production from 1960 to 1982.

Coal Production

Canadian coal deposits occur under different physical and geological conditions which affect the technical and economic aspects of mining such as the mining method, the recoverable volume of coal, and the costs of production.

In Canada, most coal is produced through surface mining. Surface mining, which employs dragline stripping, and truck and shovel stripping, is used in Western Canada and in New Brunswick. Underground mining is generally more labour intensive and is more expensive. Mining techniques used include room-and-pillar and long wall in Nova Scotia, Alberta and British Columbia and hydraulic mining in one mine in British Columbia (hydraulic mining involves the extraction of coal by a high-pressure water jet). In 1982, surface mining accounted for 91 percent of total production in Canada. In the next decade, use of underground mining could increase because the reserves suitable for surface mining are declining.

In 1982, bituminous coal represented 52 percent of Canadian coal production, while subbituminous and lignitic coals accounted for 30 percent and 18 percent, respectively.

Nova Scotia and New Brunswick together produced 3.6 megatonnes of coal in 1982 and 30 percent of this production was exported. About 9 percent of the 28 megatonnes produced in Alberta and Saskatchewan was delivered to Ontario and Manitoba and 18 percent was exported. British Columbia with a total production of 12 megatonnes, shipped 8 percent of its production to other countries.

In 1983, five new mines began production of bituminous coal through surface mining. Four of these are located in British Columbia and the other in Alber-

Coal Resources and Reserves

Canada possesses a wide range of coals: bituminous, subbituminous and lignite. In the Atlantic Provinces, coal is mainly bituminous and the sulphur content ranges from one to ten percent. Coal mined in Saskatchewan is lignitic, while Alberta produces both subbituminous and bituminous coals. Coal mined in British Columbia is bituminous. Western coals are usually low in sulphur (0.2 to 0.9 percent). As shown in Table 9-1, total recoverable reserves are 6300 megatonnes. These reserves could support an annual production of 43 megatonnes (production in 1982) for almost 150 years.

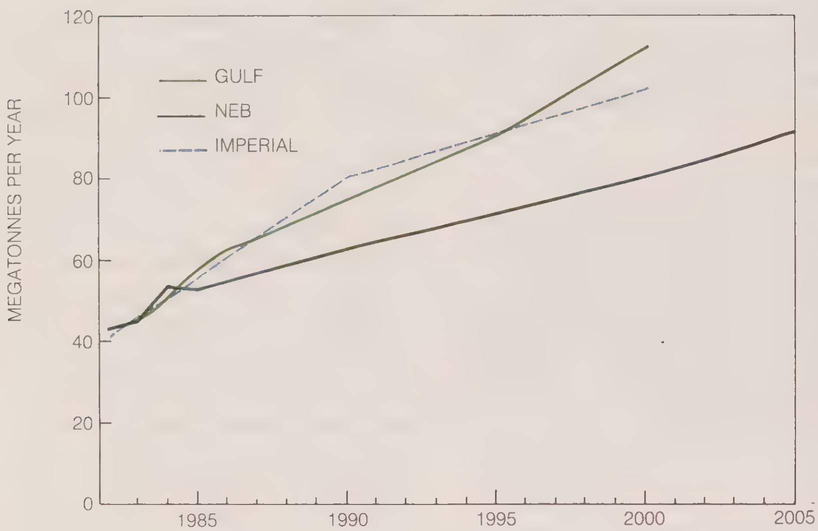
Table 9-1
Coal Resources and Reserves in Canada

		Megatonnes	Exajoules
Resources of Immediate Interest:	– Measured:	50 400	1 210
	– Indicated:	13 200	317
	– Inferred:	184 400	4 425
	Total:	**248 000**	**5 952**
Resources of Future Interest	– Measured:	200	5
	– Indicated:	4 000	96
	– Inferred:	221 600	5 318
	Total:	**225 800**	**5 419**
Recoverable Reserves (1)		6 300	151

(1) Recoverable Reserves are part of resources of immediate interest.

Source: Table A9-2, Appendix 9.

Figure 9-1
Projections of Coal Production, Canada



Source: Table A9-3, Appendix 9

ta. Recent soft world energy prices have delayed development of other mining projects contemplated.

Although coal resources are vast, the development of the coal industry depends upon factors such as transportation facilities, domestic and international markets, environment and government policies. The rail transportation system is particularly important for exports of Western coal because of the large distance between mines and open water. The coal is carried by trains to ports in Vancouver and Prince Rupert, where it is shipped to Japan and other countries. Most export demand is for coking coal. In 1982 this demand represented about 81 percent (13 megatonnes) of total exports. To supply Eastern consumers, Western coal is carried by rail to the Thunder Bay terminal for delivery via Great Lakes vessels. Through this transportation system, Ontario was supplied with about 17 percent (3 megatonnes) of its coal requirements in 1982, with the remainder imported from the United States. The Western coal is used only for electricity generation whereas the imports, which amount to 95 percent of total Canadian imports, are used for electricity generation (65 percent) and as coke in the iron and steel industry (35 percent). Although Western coal mines could supply this Ontario demand, the price advantage of coal from the United States will probably continue.

It is our opinion that the Canadian coal industry will continue to expand because of long term growth in export demand and growing electricity demand in Alberta and Saskatchewan. Figure 9-1 illustrates submittors' and our coal production forecasts. The difference between our projection and those of submittors is mainly a result of the submittors' higher export forecasts.

9.2 Primary Demand for Coal

Primary demand for coal includes, in addition to end use requirements, the use of coal to generate electricity and produce steam, own use of coal and losses associated with converting coal to coke. The principal use of coal in Canada is for the generation of electricity, mainly in Alberta and Ontario. Industry also uses coal, primarily in the production of iron and steel. The outlook for coal use in the projection period is shown in Table 9-2, and compared to submittors' projections in Figure 9-2.

Industrial use of coal is projected to increase at about two percent per year between 1983 and 2005 consistent with our outlook for growth in the output of iron and steel. Considerable uncertainty surrounds prospects for growth in this industry, however, and coal use could grow at a significantly lower rate. Coal demand could also grow more slowly in the long run if there is significant use of plasma arc technology. On the other hand, coal could be used more extensively in industrial markets as a result of the improvement in its competitive position in recent years. The use of coal for electricity generation is discussed in Chapter 5.

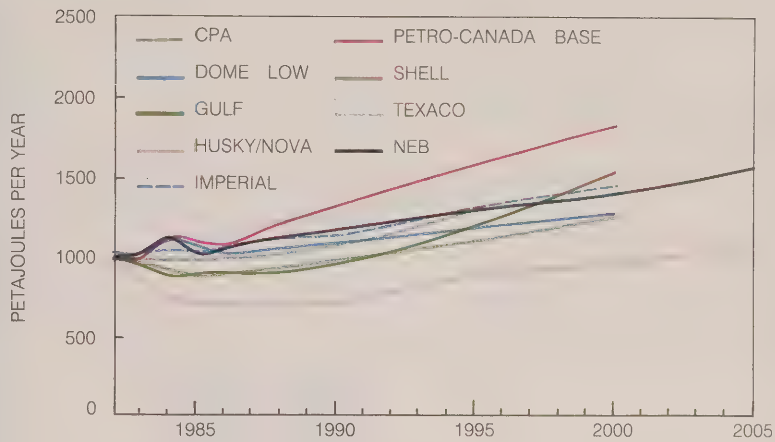
9.3 Supply/Demand Balance

Canada is a net coal exporter and, as shown in Figure 9-3, this situation is expected to continue for the forecast period. Table 9-3 shows exports and imports by coal type for 1983. It is apparent that Canada is a net importer of thermal coal. The dependency on im-

ports is caused by the geographical distribution of coal resources which gives coal from the United States a competitive advantage in Ontario.

Imports, which were 14.7 megatonnes or 25 percent of total supply in 1983, are projected to remain virtually constant in absolute terms but to decline in relative terms to 14 percent of total supply in 2005. This projection is based on the assumption that the competitive advantage of coal from the United States in Ontario will continue over the forecast period. The recent recession in the world economy has depressed demand for Canadian coal in the export market. Despite the current market weakness, the long-term outlook for Canadian coal exports is favourable. Exports, which were 29 percent of total coal demand in 1983, are projected to represent about 38 percent of Canadian coal demand in 2005.

Figure 9-2
Projections of Primary Demand for Coal, Canada



Source: Table A9-4, Appendix 9

Table 9-2
Primary Demand for Coal

(Petajoules)

	1983	1990	2005
Industrial	230	273	371
Electricity Generation	757	860	1154
Other	31	28	32
Primary	1018	1161	1557

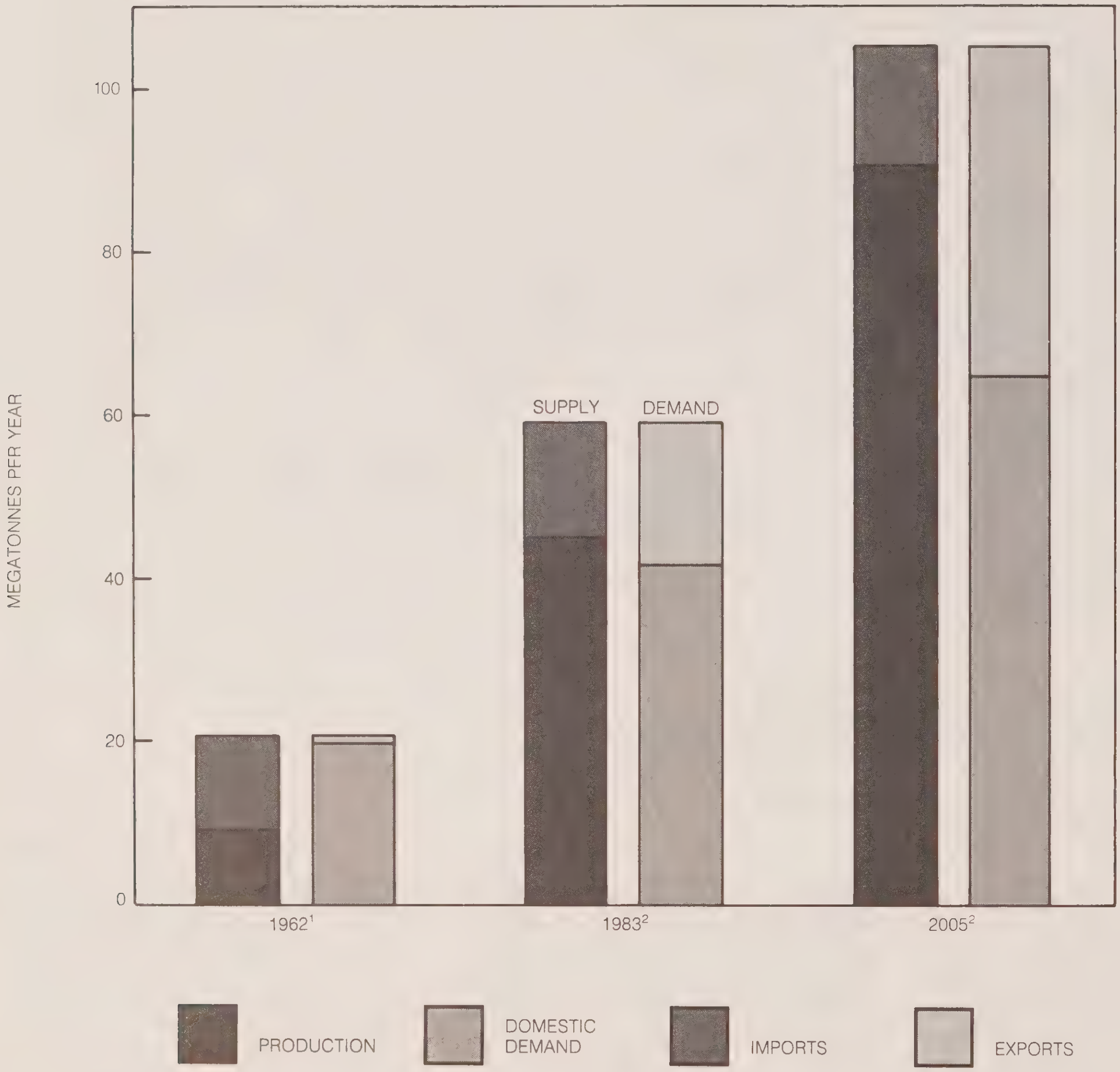
Table 9-3
Imports and Exports of Thermal and Metallurgical Coal 1983

(megatonnes)

	Exports	Imports	Net Exports (Imports)
Metallurgical Coal	14.5	6.2	8.3
Thermal Coal	2.5	8.5	(6.0)
Total	17.0	14.7	2.3

Source: Energy, Mines and Resources

Figure 9-3
Coal Supply and Demand, Canada



[1]Source: Statistics Canada
[2]Source: Table A9-5, Appendix 9

CHAPTER 10

SOURCES AND USES OF PRIMARY ENERGY

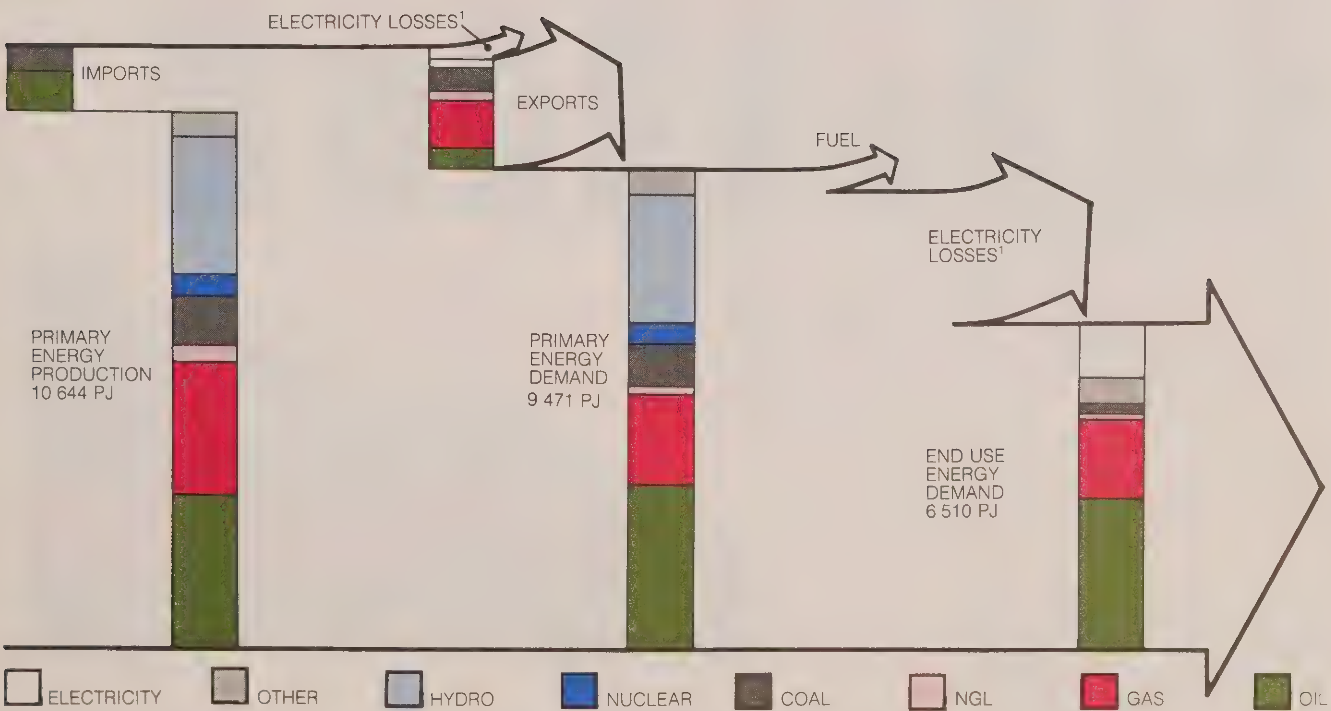
This chapter outlines the sources and disposition of energy flows in Canada at the present time, and draws together the implications of the analysis of preceding chapters for the evolution of those flows between now and 2005. The analysis is conducted in terms of primary energy, i.e., in terms of the total quantities of the various energy forms used in the country.

Figure 10-1 shows the relationships among end use energy demand, primary energy demand and energy production in Canada in 1982. To arrive at the amount of primary energy used, we add to end use demand the amount of fuel and losses associated with the production and distribution of energy. The amounts of energy used by the supply industries include:

- fuel needed to produce and move oil and natural gas to markets;
- fuel and losses incurred in the refining of crude oil to produce petroleum products, and the reprocessing of gas to remove natural gas liquids;
- utility own use and losses in the transmission and distribution of electrical power;
- conversion losses in electricity generation when coal, gas and oil are consumed in generating plants; approximately three units of fossil fuel input are needed to produce one unit of electricity; and
- in most primary energy statistics, an imputed loss is added for the electricity generated by hydraulic and nuclear means.

The calculation of the primary energy associated with the production of hydroelectricity is conceptually difficult because no fuels are consumed in the

Figure 10-1
ENERGY FLOWS
(Based on 1982 Data)



Source: Table A10-3, Appendix 10

[1]Approximately 70 per cent of this component is theoretical losses attributed to use of the fossil fuel input equivalent for hydro and nuclear power generation. About 20 per cent of this component is physically lost in generating electricity from fossil fuels. About 10 per cent is losses in electricity transmission

usual sense of the term. Nuclear generated electricity presents a problem because only a portion of the nuclear energy in the uranium fuel is used. The nuclear energy that is released as heat is, however, used at about the same efficiency as in a fossil fuel generator. There are two ways of calculating the primary energy associated with hydro and nuclear power:

- We can simply recognize that hydro and nuclear power are different and define their primary energy as the energy produced at the dam site, in the case of hydro, and the plant gate in the case of nuclear. Measured this way the primary energy associated with the production of hydro and nuclear electricity would be equal to the energy content of the electricity output, 3.6 petajoules per terawatt hour. For convenience we label this the energy output method.
- A second method is frequently used, particularly when comparisons are being made of energy use across countries. This method (labelled the fossil fuel equivalence method) assumes that the amount of primary energy associated with hydro and nuclear electricity is the amount which would be required if fossil fuels were used. Using this method a conversion factor of 10.5 petajoules per terawatt hour is adopted because methods of generation using fossil fuels have, on average, an efficiency of about 33 percent.

Use of the second method implies that the amount of primary energy attributed to hydro will be much larger than the amount of electrical energy produced.

Because the fossil fuel equivalence conversion is widely used and has been used in previous Board reports, our primary energy projections (Appendix 10) use this method. In the text and tables in this chapter we show primary energy on both bases for purposes of comparison.

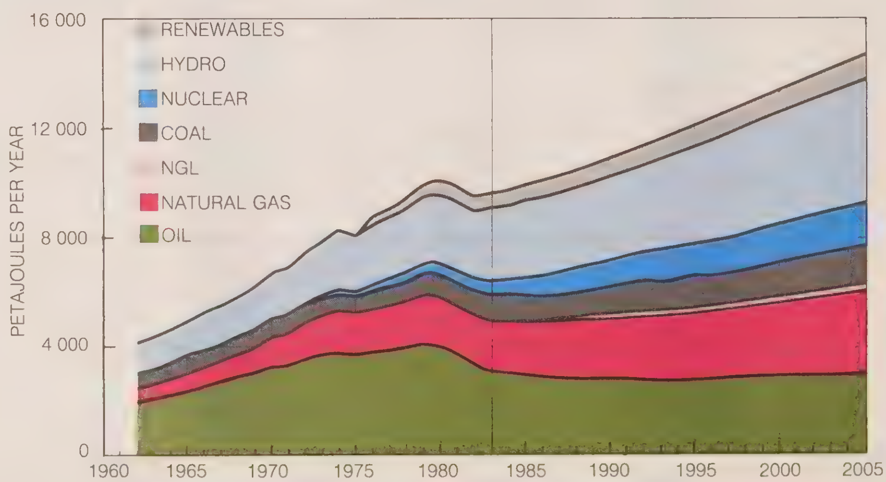
The arrow labelled fuel in Figure 10-1 shows the heat content of fuels used in the production and transportation of final energy other than fossil fuels used in the production of electricity.

Some 70 percent of the large electricity losses are imputed losses resulting from our use of the fossil fuel equivalence conversion method. Of the remainder about two-thirds are actual losses resulting from the use of conventional fuels to generate electricity and one-third results from transmission losses.

Given the differences in definitions of primary and end use energy it is not surprising that their distribution across energy forms is quite different and that primary energy is much larger than end use energy. Differences in the treatment of electricity account for most of the distributional shift and much of the difference in levels. Had hydro and nuclear electricity been included in primary energy at their energy content value the level of primary energy in 1982 would have been 7550 petajoules instead of 9470 petajoules and the share of hydro and nuclear 13 percent instead of 31 percent. The primary demand for coal is also much larger than end use demand because primary demand includes the quantities used to generate electricity. Only minor amounts of oil and gas are used to generate electricity.

Primary energy production in Canada will differ from primary energy demand to the extent that we are net importers or exporters of energy. In 1982 Canada was a large exporter of natural gas and natural gas liquids, a modest exporter of electricity, a net importer of crude oil and, to a marginal extent, a net exporter of coal.

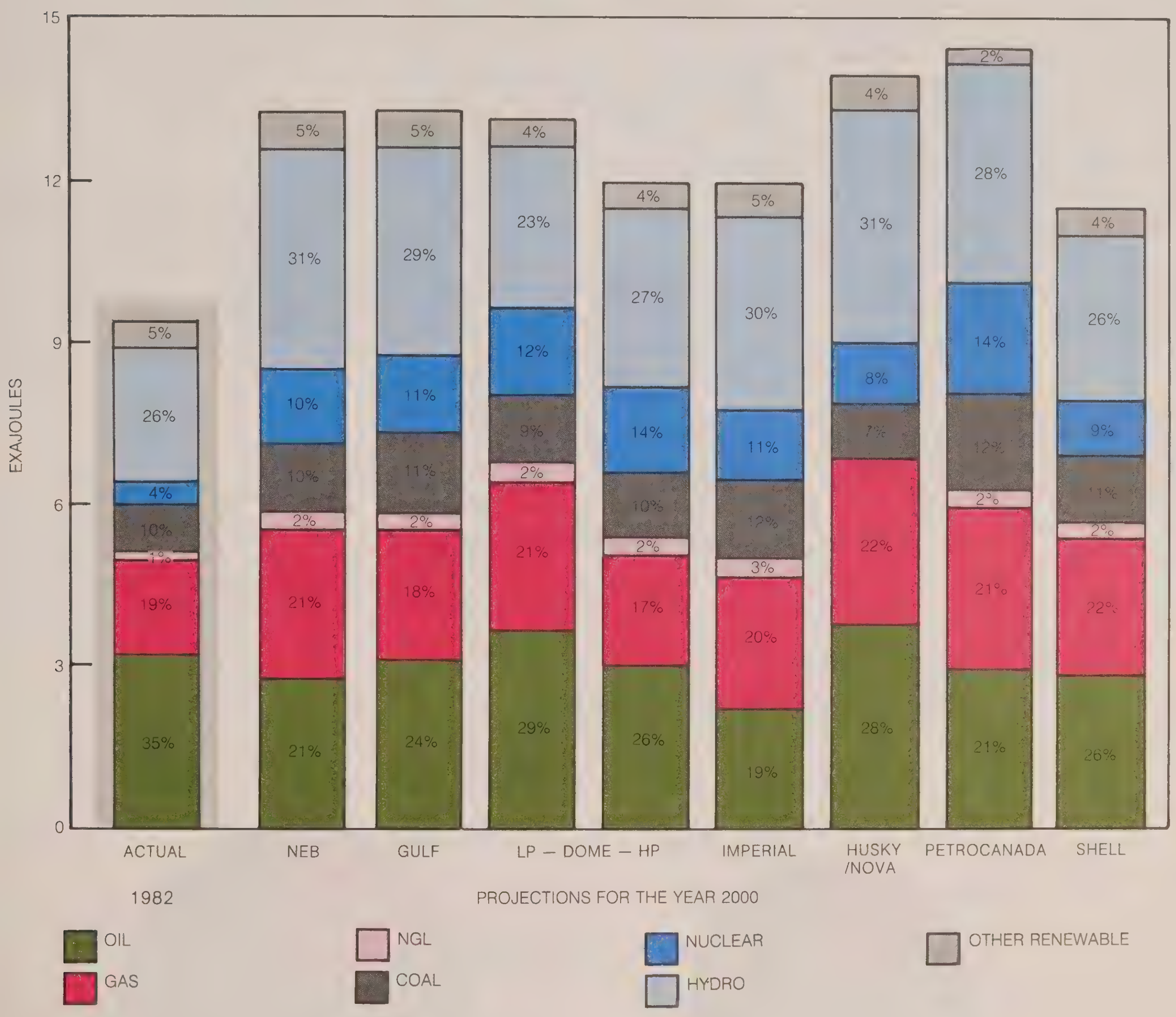
Figure 10-2
Primary Energy Demand,[1] Canada



Source: Table A10-3, Appendix 10

[1]Hydro and nuclear converted at 10.5 PJ/TW.h (fossil fuel equivalence)

Figure 10-3
Comparison of Primary Energy Demand Projections



Source: Table A10-1, Appendix 10

10.1 Projections of Primary Energy Demand and Production

Figure 10-2 shows the projected evolution of the components of primary energy demand over our projection horizon. Our projections are compared with those of submittors in Figure 10-3.

The growth and pattern of primary energy over our projection horizon largely reflects the projected evolution of end use requirements described in previous chapters. The evolution of the distribution of primary energy is shown

in Table 10-1 using both fossil fuel equivalence and energy output methods of calculating primary hydro and nuclear electricity. A graphical depiction using the fossil fuel equivalence method is shown in Figure 10-4. The distribution of primary energy shifts towards hydro and nuclear electricity and natural gas, and substantially away from oil, by 2005. The change in the distribution is broadly similar under both methods of accounting for primary hydro and nuclear electricity but, as expected, fossil fuel equivalence ascribes a much larger share to hydro and nuclear than does energy output.

Because Canada produces most of the energy it consumes it is not surprising that the pattern of growth of energy production, shown in Table 10-2 and Figure 10-5, is broadly similar to the pattern discussed above for primary energy demand. The share of coal is significantly larger in 2005 and shares for other energy forms slightly smaller than are the corresponding shares for primary energy demand. This reflects our projection that coal exports will increase appreciably over the projection horizon.

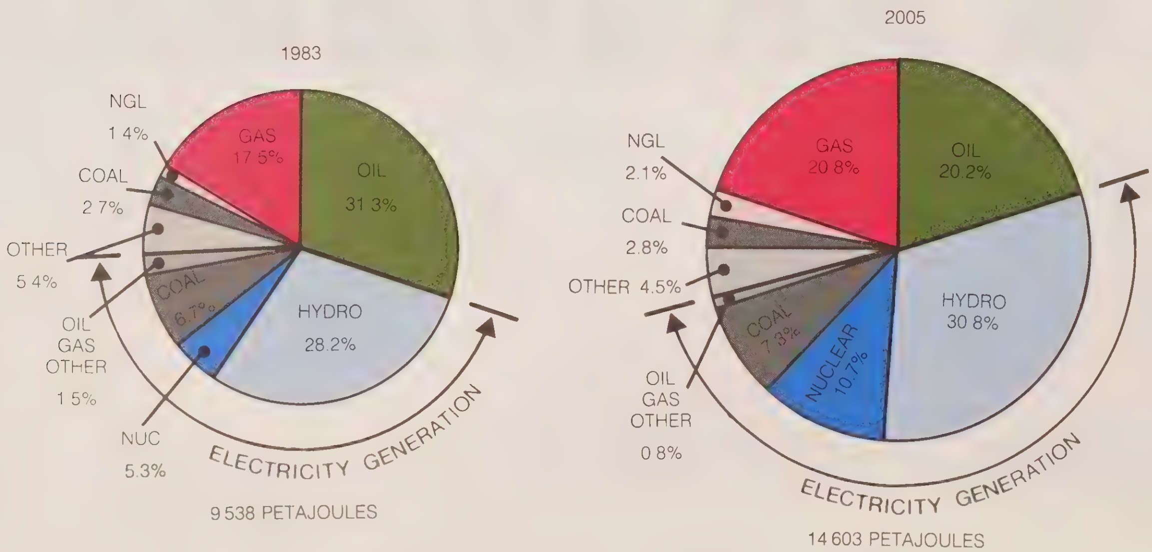
10.2 Net Exports of Energy

Canada has, since the mid-1960s, produced energy in excess of its needs and has tended to be a significant net exporter of energy. In 1983 the value of net energy exports from Canada was some $7.8 billion.

Our projections (Table 10-3) suggest that during the remaining years of this decade we will continue to be net energy exporters:

- Net exports of oil are likely to decline as domestic demand outpaces our productive capacity.
- Natural gas exports are projected to rise rapidly in the remaining years of this decade to 90 percent of their authorized level by 1990, more than doubling in amount from current levels.

Figure 10-4
Primary Energy Demand[1], Canada



Source: Table A10-3, Appendix 10

[1]Hydro and nuclear converted at 10.5 PJ/TW.h (fossil fuel equivalence)

- NGL have for some time been produced in excess of domestic demand. This is likely to continue but quantities available for export are projected to decline as Canadian demand rises relative to supply.

- Canada has recently become a net exporter of coal after having been a net importer for many years. We project a substantial increase in coal exports primarily as a consequence of the development of Western coal deposits.

- Exports of electricity have increased substantially in recent years. They consist mainly of interruptible energy although there is now more interest in the export of firm power as utilities view the possible needs of United States utilities for additional generating capacity in the 1990s. We estimate that potential exports of electricity will increase significantly until the late 1980s when surpluses will decrease as Canadian needs increase.

Table 10-1
Distribution of Primary Energy Demand

(Percent)

	Fossil Fuel Equivalence[1]			Energy Output[2]		
	1962	1983	2005	1962	1983	2005
Oil	47	32	21	57	44	29
Gas	11	18	21	13	24	29
Coal	13	10	10	15	12	14
Nuclear	—	5	11	—	2	5
Hydro	26	28	31	11	11	15
Other	3	7	6	4	7	8
Total	100	100	100	100	100	100

(1) Hydro and nuclear converted at 10.5 petajoules per terawatt hour.
(2) Hydro and nuclear converted at 3.6 petajoules per terawatt hour.

Table 10-2
Distribution of Primary Energy Production

(Percent)

	Fossil Fuel Equivalence[1]			Energy Output[2]		
	1962	1983	2005	1962	1983	2005
Oil	41	30	20	50	37	27
Gas	22	22	19	27	27	26
Coal	6	10	13	7	13	18
Nuclear	—	5	11	—	2	5
Hydro	28	25	30	12	11	14
Other	3	8	7	4	10	10
Total	100	100	100	100	100	100

(1) Hydro and nuclear converted at 10.5 petajoules per terawatt hour.
(2) Hydro and nuclear converted at 3.6 petajoules per terawatt hour.

In the years beyond 1990 our projections imply that, without the development and production of frontier reserves, our potential for natural gas exports will decline significantly. Canadian oil markets will be close to being in balance and potential exports of NGL are likely to decline as Canadian demand increases, particularly for NGL as petrochemical feedstocks and as fluids in enhanced oil recovery projects.

Coal and electricity may well provide the greatest potential for sustained exports of Canadian energy, coal because we have very large deposits relative to our foreseeable needs and electricity because the gradual expansion of generating capacity in Canada may make available larger amounts of interruptible energy to neighbouring markets in the United States. In addition, some utilities are considering the construction of generating capacity dedicated to export markets.

10.3 International Perspectives

Canada is a large consumer and producer of energy. On a per capita basis, Canadians are among the highest consumers and producers in the world. A considerable amount of our energy is used in the manufacture of energy intensive products. Canada has, for example, a relatively high out-

put of aluminium, wood pulp, newsprint and petroleum products the production of which requires large amounts of energy. A large proportion of the production of these goods is exported but the energy used in their production is not included in importing countries' energy consumption. Other factors, climate, geography and population density, also influence the consumption of energy in Canada.

To provide an international perspective, Table 10-4 compares energy use in Canada and other OECD member countries.

Table 10-3
Net Energy Exports (Imports)

(Petajoules)

	1973	1983	1990
Oil	611	224	18
Gas	1125	751	1844
NGL	154	198	136
Coal	(131)	64	335
Electricity			
– Fossil Fuel Equivalence	169	379	441
– Energy Output	61	131	164

Table 10-4
Selected Indicators of Energy Use and Production – 1982

					Primary Demand			
					Fossil Fuel Equivalent		Energy Content	
	Population (millions)	Gross Domestic Product ($U.S., billion)	Primary Demand (PJ)	Production (PJ)	Per Capita (GJ)	Per GDP (MJ)	Per Capita (GJ)	Per GDP (MJ)
Canada	24.7	363	9086	9968	368	25	298	20
U.S.	232.1	3708	73291	66959	316	20	301	19
Japan	118.4	1295	14388	2462	121	11	111	10
Australia	15.2	192	3307	4392	218	17	213	17
New Zealand	3.2	29	476	358	150	16	116	12
Austria	7.6	82	1080	488	143	13	120	11
Belgium	9.9	103	1746	354	177	17	177	17
Denmark	5.1	69	736	88	144	11	144	11
Finland	4.8	60	1085	499	225	18	183	15
France	54.2	659	7742	2612	143	12	124	10
Germany	61.6	804	10666	5481	173	13	165	12
Greece	9.8	47	666	231	68	14	66	14
Iceland	0.2	3	57	34	242	18	138	11
Ireland	3.5	21	361	136	104	17	102	17
Italy	56.6	424	5642	1169	100	13	95	12
Luxembourg	0.4	4	130	5	356	32	349	31
Netherlands	14.3	168	2345	2453	164	14	162	14
Norway	4.1	69	997	2618	242	15	181	11
Portugal	10.0	29	510	98	51	18	47	17
Spain	37.9	221	3100	1001	82	14	77	13
Sweden	8.3	121	1960	1048	235	16	170	12
Switzerland	6.5	118	1027	518	159	9	113	6
Turkey	46.8	65	1528	919	33	24	31	23
U.K.	56.3	582	8236	9404	146	14	141	14

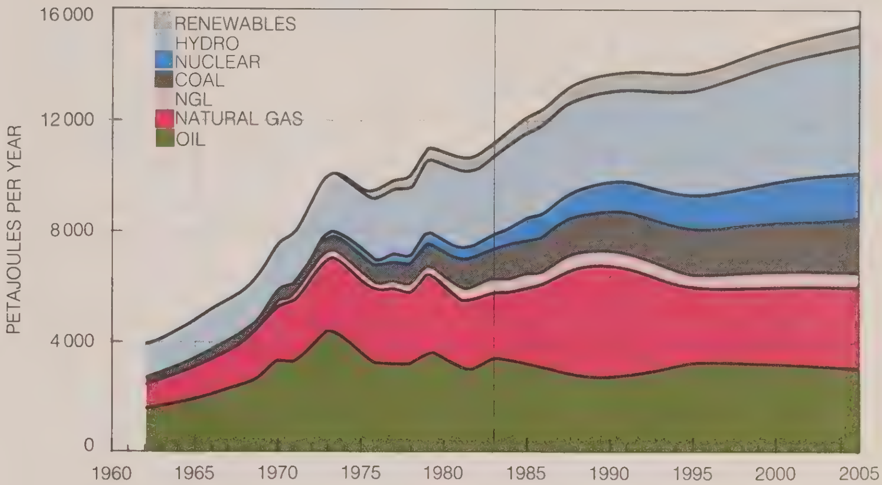
Sources: OECD, Energy Balances of OECD Countries 1970-1982, Paris 1984; OECD Observer No. 127, March 1984

This table compares primary energy use; production of hydro and nuclear electricity are valued at their fossil fuel equivalence. On this basis Canada was the largest consumer of primary energy on a per capita basis in 1982. Per dollar of national product Canada was the second highest consumer of energy.

As shown in Table 10-4, if hydro and nuclear electricity are measured at the energy output method, Canadian energy use per capita and per dollar of output would be about one-fifth lower than if measured at fossil fuel equivalence. Using this measure Canadian energy use is about equal to that of the United States instead of being perceived to be significantly greater.

The degree to which a country is self-sufficient in total energy can be estimated by dividing total domestic energy production by total primary energy demand. In 1982, Canada ranked fourth in self-sufficiency among the OECD countries – producing about ten percent more energy than it consumed.

Figure 10-5
Primary Energy Production[1], Canada



Source: Table A10-3, Appendix 10
[1]Hydro and nuclear converted at 10.5 PJ/TW.h (fossil fuel equivalence)

CHAPTER 11

CONCLUSIONS

In this report we have sketched our view of the broad outlines of likely developments in Canadian energy markets over the next 20 years in light of our analysis of information currently available about the prospects for major underlying variables and about their impact on energy supply and demand. We have emphasized that the course of future developments is critically dependent on a number of underlying variables the future of which is unclear at best and on which views of the prospects have changed considerably in recent years.

Over a period of 20 years it is virtually certain that developments will be different, in greater or lesser degree, than the course which we have outlined. Surprises, inherently unforeseeable, will occur and it is entirely possible that history will unfold in a quite different way from that which we have assumed. Even in a short time frame, key factors can change in ways that were not foreseen, witness the size of the 1982 recession.

Canadian energy markets have changed considerably in recent years:

- they have been influenced by dramatic changes in actual and expected world oil prices,
- there have been substantial changes in the conditions in export markets for Canadian energy, particularly for gas but also for electricity,
- there have been major changes in Canadian energy policies, and
- energy markets have been powerfully influenced by and, in turn, have influenced, the course of economic growth.

Both demand and supply for energy in total and for different energy forms have responded to these changes, especially to price changes, to a larger extent than many would have predicted even five years ago.

Canada and the world are now in a position where supplies of energy forms generally exceed the amounts being used. As a consequence, the focus of attention of analysts has shifted considerably:

- During the 1970s concerns about the supply of energy, oil and gas and, to a lesser extent, electricity, dominated energy markets.
- Thus far in the 1980s the concern has shifted to the demand for energy.

The shift in focus in Canada is associated particularly with natural gas and electricity. The large price increases in the 1970s resulted in a large increase in the supply of Canadian natural gas. The fact that electricity demand had been growing very rapidly in the 1960s and early 1970s, led electric utilities to implement very large expansion plans. Demand, however, has since weakened considerably, influenced by rising relative prices for energy and by relatively weak economic growth.

The crude oil picture is mixed. Though developments in oil demand and supply have broadly mirrored developments in other energy forms, considerable concern continues to exist about the security of oil supply even though, on a world scale, there exists at present a large excess supply. Governments, including the Canadian government, remain extremely concerned about the possibility of future supply disruptions and price shocks. Consequently, in countries such as Canada, which have significant potential supplies of crude oil, governments are concerned that supplies be developed expeditiously to minimize dependence on insecure foreign sources of supply.

Demand

Our assessment of energy demand in Canada suggests that, though energy use will continue to grow over the next quarter century, growth in its use will be much lower than occurred during the 1960s and significantly lower than in the 1970s. Energy demand in Canada would, in all probability, grow at a lower rate even in the absence of the rapid price increases which have occurred because population and economic growth will be lower than they were in the past two decades. Evidence is accumulating, however, that the slowdown in the growth of energy demand is likely to be much more substantial than that implied by current assessments of economic and demographic trends. The response of energy users to past increases in energy prices is still working its way through the economy and is likely to be much larger than was previously thought.

Based on our own analysis and on discussions with submittors to this inquiry, we conclude that a substantial part of the response to past price increases has yet to occur. Our Reference Case was constructed on the assumption that economic growth would be moderate. Even were this growth to be significantly greater, we estimate that growth in energy demand would average just over 2 percent per year between 1983 and 2005 compared with a rate of 5 percent per year in the 1960s and about 3.5 percent in 1973-78. The impact of increases in GNP on energy use is substantially mitigated by energy conservation. By the year 2005, it is reasonable to conclude that the energy intensity of the Canadian economy will have declined by some 27 percent from its 1983 level.

There has already been a large shift away from the use of oil in Canada. We think this movement will continue, albeit at a declining rate, and that by the turn of the century oil use in Canada will comprise approximately 30 percent of end use energy demand compared with 59 percent in 1973 and 43 percent now. The use of oil products is increasingly dominated by their use in transportation

for which there is no broadly acceptable substitute fuel. By the turn of the century transportation uses will make up most of the demand for oil in Canada. It is unlikely that alternative transportation fuels will be in widespread use by 2005, though we assume that the use of natural gas and propane will increase significantly, particularly by commercial users with large fleets.

It is highly likely that both natural gas and electricity will gain from the shift away from oil. We have assumed that both would gain in about equal proportions, but interfuel competition is intense and the outcome very difficult to call. Electricity growth may well be particularly strong over the next three or four years as utilities seek to dispose of existing surpluses.

Canada has large coal resources concentrated in Alberta and British Columbia and, to a much lesser extent, in the Maritime provinces. Exports have risen substantially in recent years and we project growth in export sales to continue to be stronger than growth in domestic demand so that, by 2005, export sales will account for some 40 percent of domestic production compared to about 20 percent in 1983.

The extent to which Canadians use larger amounts of alternative, renewable, energy forms over the next twenty years will depend both on economic and technological factors. Given the current state of technology and the range of oil prices which we used in conducting our analysis, we conclude that the use of alternative energy forms will continue to increase, but their share of total energy demand is unlikely to exceed some seven or eight percent. Either energy prices would have to increase much more rapidly than now seems likely, or significant technological breakthroughs would be required, in order for such alternative energy forms as solar or biomass to make a larger contribution to meeting our energy needs.

Supply

In broad terms and over a long run horizon, our analysis suggests that, while Canada has large supplies of hydrocarbons, these will be increasingly costly and difficult to extract. In the case of oil, the rising costs relate to the cost of extraction as well as to the processing of the raw material into usable products.

The rising cost profile results because:

- it is probable that we have already extracted the cheapest oil and gas from conventional producing areas; further supplies will be more costly to find and, having been found, will be more costly to produce,
- the fact that reserves from conventional producing areas are gradually being depleted implies that, to sustain our supply of hydrocarbons, we will increasingly be dependent on potential production from frontier regions which is expensive to find, and on production of oil from the oil sands which is expensive to produce.

There was a very large increase in the production of crude oil in Canada during the 1960s since which time there has been a gradual but steady decline. Our projections suggest that this gradual decline will continue as reserves of crude oil in conventional producing areas continue to decline. The decline will, however, be mitigated by improved recovery of oil from existing fields, as enhanced recovery techniques are used to a greater extent, and by new discoveries in Western Canada.

Our assessment of the economics of integrated oil sands plants producing synthetic crude oil suggests that such plants will be in the national interest if the cost of imported oil evolves as projected in our Reference Case. We have included in our oil supply projection two further oil sands plants of the Syncrude/Suncor variety and additional bitumen projects.

Nonetheless it is highly likely that, by the turn of the century, light crude oil from Western Canada, including synthetic oil from integrated oil sands plants, will account for only about 50 percent of our total crude oil supply compared with its current share of 80 percent. The geological potential of frontier regions is uncertain; we have included production from Hibernia in our projections and, more tentatively, production from the Beaufort Sea. By the end of the projection horizon, frontier sources account for some 20 percent of projected Canadian oil supply.

Over our projection horizon the source of natural gas supply remains overwhelmingly the Western Canada Sedimentary Basin. We assume that Scotian Shelf gas will reach markets in the Maritime provinces in the early 1990s, but the timing and quantity of gas from northern frontier regions is uncertain. Deliveries could begin from the Mackenzie Delta area as early as 1995. In any event, quantities of natural gas from unconventional sources and/or frontier regions seem likely to remain relatively small over our projection horizon.

Coal supply development will be paced by the growth in export demand and growing use for electricity generation in Alberta and Saskatchewan.

Energy Balances and Implications

While in total, Canada's crude oil supply and demand over the projection period are essentially in balance, a deficiency in light oil supply occurs in most years. This deficiency will be severely exacerbated as time goes on, unless significant quantities of new production

are forthcoming from the frontier regions and the oil sands. In a sense, supply from these two sources can be considered as a unit, since additional oil sands production could compensate for deficiencies in frontier production, and conversely, frontier supplies substantially in excess of our projection could reduce the volume of oil sands production required to meet future demand. The extent and timing of development of each of these resources will depend critically on economic factors, particularly the course of world oil prices. Because the average quality of crude oil in Canada and in the world is likely to decline over time, the refining process, which transforms crude oil into usable refined petroleum products, is likely to become more complex and therefore more expensive.

There is, at present, an excess of natural gas deliverability in Canada as a result of the large additions to reserves from 1976 through 1981, and the current weakness in domestic and export markets. This excess deliverability diminishes as the decade unfolds with the anticipated expansion of United States markets and domestic demand. During the 1990s some surplus capability is likely to remain with no deficiency developing until after the turn of the century. It is likely however, that, to maintain supplies of the size that we have projected, the price of gas will have to rise gradually over time relative to the price of other goods and services both at the wellhead and at the point of end use. In our view, the supplies we have projected are likely to be forthcoming given present Canadian pricing policies and our Reference Case profile for world and domestic oil prices. Should oil prices follow a course significantly weaker than that projected in our Reference Case, domestic gas prices would have to rise relative to the price of oil.

Our projections imply that expansion of electricity generating capacity beyond that already committed will not be required for some time to come and that in the 1990s the rate of expansion to serve domestic markets will be significantly less than that witnessed in the 1970s. A number of utilities are, however, contemplating the construction of facilities dedicated to the export of electricity to the United States.

Overall, our analysis suggests that over the next decade, Canadian energy markets, in common with those in much of the rest of the world, will be characterized more by an excess of supply than of demand. Increasingly, as time goes on, demand is likely to press against supply and further adjustment of demand to a diminishing supply of conventional energy resources will be required. The ease with which such adjustments take place will depend on a number of factors, including in particular the extent to which technological change makes renewable resources and resources now considered unconventional, more accessible.

Appendices

List of Appendices

Appendix 1

A1-1 List of Submittors
A1-2 List of Reference Reports
A1-3 Abbreviations of Names and Terms
A1-4 Definitions
A1-5 Conversion Factors
A1-6 Guidelines for Submission

Appendix 2

Table A2-1 World Oil Prices – Comparision of Submittors' Views
Table A2-2 Real Gross National Product Growth Rates – Canada – Comparison of Submittors' Views
Table A2-3 Real Provincial Domestic Product Growth Rates – Canada and Regions – Comparison of Submittors' Views

Appendix 3

Table A3-1 Historical Data – End Use Energy Demand by Sector – Canada
Table A3-2 End Use Energy Demand by Sector – Canada and Regions – Comparison of Submittors' Views

Appendix 4

Table A4-1 Historical Data – End Use Energy Demand by Fuel – Canada
Table A4-2 End Use Energy Demand by Fuel – Canada and Regions – Comparison of Submittors' Views
Table A4-3 Relative Energy Prices by Regions – NEB Projection
Table A4-4 Distribution of End Use Energy Demand by Fuel and Sector – Canada and Regions – NEB Projection

Appendix 5

Table A5-1 Electricity Demand Growth Rates – Comparison of Submittors' Views
Table A5-2 Historical Data – Total Demand for Electricity by Sector – Canada
Table A5-3 Total Demand for Electricity by Sector – Canada – NEB Projection
Table A5-4 Generating Capacity by Fuel Type – Canada and Provinces – NEB Projection
Table A5-5 Energy Generation by Fuel Type – Canada and Provinces – NEB Projection
Table A5-6 Demand for Fuel Sources for Generation of Electricity – Canada – NEB Projection
Table A5-7 Net Electricity Exports – NEB Projection
Table A5-8 Electricity Exports by Fuel Type – NEB Projection

Appendix 6

Table A6-1 Historical Data – Established Reserves and Cumulative Production of Marketable Natural Gas From Conventional Producing Areas
Table A6-2 Natural Gas Reserves Additions Per Unit of Exploratory Drilling and Initial Established Reserves – Conventional Producing Areas
Table A6-3 Exploratory Drilling Activity – Historical Data and NEB Projection
Table A6-4 Exploratory Drilling Activity by Province – NEB Projection
Table A6-5 Marketable Natural Gas Reserves Additions – Historical Data and NEB Projection
Table A6-6 Marketable Natural Gas Reserves Additions from Appreciation and New Discoveries – Conventional Areas – NEB Projection

Table A6-7	Marketable Natural Gas Reserves Additions – Conventional Areas – Comparison of Submittors' Views
Table A6-8	Deliverability from Established Reserves – Comparison of Submittors' Views
Table A6-9	Deliverability from Conventional Producing Areas – Established Reserves and Reserves Additions – Comparison of Submittors' Views
Table A6-10	Deliverability from Frontier Regions – Comparison of Submittors' Views
Table A6-11	Deliverability from Conventional Areas – NEB Projection
Table A6-12	Deliverability from All Sources – NEB Projection
Table A6-13	Connection Rates for Gas Reserves – NEB Projection
Table A6-14	Natural Gas Exports by Licence – NEB Projection
Table A6-15	Short Term Natural Gas Exports – Comparison of Submittors' Views
Table A6-16	Natural Gas Exports – History and NEB Projection
Table A6-17	Historical Data – Primary Demand for Natural Gas – Canada
Table A6-18	Primary Demand for Natural Gas – Canada – Comparison of Submittors' Views
Table A6-19	Historical Data – Natural Gas Supply and Demand – Canada
Table A6-20	Natural Gas Supply and Demand – Conventional Areas – NEB Projection

Appendix 7

Table A7-1	Historical Data – Production of Crude Oil and Equivalent
Table A7-2	Historical Data – Established Reserves and Cumulative Production of Conventional Crude Oil
Table A7-3	Productive Capacity of Crude Oil and Equivalent – Canada – NEB Projection
Table A7-4	Conventional Crude Oil – Established Reserves and Productive Capacity by Province – NEB Projection
Table A7-5	Conventional Crude Oil – Established Reserves and Productive Capacity by Pool – NEB Projection
Table A7-6	Annual Reserves Additions of Conventional Light Crude – NEB Projection
Table A7-7	Productive Capacity from Reserves Additions of Conventional Light Crude – NEB Projection
Table A7-8	Annual Reserves Additions of Conventional Heavy Crude – NEB Projection
Table A7-9	Productive Capacity from Reserves Additions of Conventional Heavy Crude – NEB Projection
Table A7-10	Ultimate Potential of Conventional Crude Oil in Conventional Producing Areas – NEB Projection
Table A7-11	NEB Basic Assumptions for Converting Reserves Additions to Productive Capacity
Table A7-12	Active or Planned Enchanced Oil Recovery Projects
Table A7-13	Oil Sands Supply – NEB Projection
Table A7-14	Productive Capacity of Crude Oil and Equivalent – Comparison of Submittors' Views
Table A7-15	Productive Capacity of Light Crude Oil – Comparison of Submittors' Views
Table A7-16	Productive Capacity of Heavy Crude Oil – Comparison of Submittors' Views
Table A7-17	Productive Capacity from Established Reserves of Light Crude Oil – Comparison of Submittors' Views
Table A7-18	Productive Capacity from Established Reserves of Heavy Crude Oil – Comparison of Submittors' Views
Table A7-19	Productive Capacity from Future Appreciation and New Discoveries of Conventional Light Crude Oil Excluding Appreciation of Currently Established Reserves Through Enhanced Recovery – Comparison of Submittors' Views
Table A7-20	Productive Capacity from Future Appreciation and New Discoveries of Conventional Heavy Crude Oil Excluding Appreciation of Currently Established Reserves Through Enhanced Recovery – Comparison of Submittors' Views
Table A7-21	Productive Capacity from Appreciation of Currently Established Light Crude Oil Reserves Through Enchanced Recovery – Comparison of Submittors' Views
Table A7-22	Productive Capacity from Appreciation of Currently Established Heavy Crude Oil Reserves Through Enchanced Recovery – Comparison of Submittors' Views
Table A7-23	Productive Capacity from Frontier Operations – Comparison of Submittors' Views
Table A7-24	Productive Capacity of Synthetic Oil – Comparison of Submittors' Views
Table A7-25	Productive Capacity of Crude Bitumen from Oil Sands Mining and In Situ Operations – Comparison of Submittors' Views
Table A7-26	Productive Capacity of Pentanes Plus – Comparison of Submittors' Views

Table A7-27	Annual Reserves Additions from Future Appreciation and New Discoveries of Conventional Light Crude Oil Excluding Appreciation of Currently Established Reserves Through Enhanced Recovery – Comparison of Submittors' Views
Table A7-28	Annual Reserves Additions from Future Appreciation and New Discoveries of Conventional Heavy Crude Oil Excluding Appreciation of Currently Established Reserves Through Enhanced Recovery – Comparison of Submittors' Views
Table A7-29	Annual Reserves Additions from Appreciation of Currently Established Light Crude Oil Reserves Through Enhanced Oil Recovery – Comparison of Submittors' Views
Table A7-30	Annual Reserves Additions from Appreciation of Currently Established Heavy Crude Oil Reserves Through Enhanced Oil Recovery – Comparison of Submittors' Views
Table A7-31	Historical Data – Primary Demand for Oil – Canada
Table A7-32	Primary Demand for Oil – Canada – Comparison of Submittors' Views
Table A7-33	Total Petroleum Product Demand – Canada and Regions – NEB Projection
Table A7-34	Refinery Feedstock Requirements – Canada and Regions – NEB Projection
Table A7-35	Crude Oil and Equivalent Supply and Demand – Canada – NEB Projection

Appendix 8

Table A8-1	Historical Data – Production of Natural Gas Liquids
Table A8-2	Natural Gas Liquids Production – NEB Projection
Table A8-3	Ethane Supply from Gas Plants – Comparison of Submittors' Views
Table A8-4	Propane Supply from Gas Plants – Comparison of Submittors' Views
Table A8-5	Butanes Supply from Gas Plants – Comparison of Submittors' Views
Table A8-6	Pentanes Plus Supply from Gas Plants – Comparison of Submittors' Views
Table A8-7	Propane Supply from Refineries – Comparison of Submittors' Views
Table A8-8	Butanes Supply from Refineries – Comparison of Submittors' Views
Table A8-9	Ethane Production by Gas Plant – NEB Projection
Table A8-10	Propane Production by Gas Plant – NEB Projection
Table A8-11	Butanes Production by Gas Plant – NEB Projection
Table A8-12	Pentanes Plus Production by Gas Plant – NEB Projection
Table A8-13	Propane Production from Refineries – NEB Projection
Table A8-14	Butanes Production from Refineries – NEB Projection
Table A8-15	Natural Gas Liquids Net Export Licences – NEB Projection
Table A8-16	End Use Demand for Ethane, Propane and Butanes by Sector – Canada – NEB Projection
Table A8-17	Primary Demand for Natural Gas Liquids – Canada – Comparison of Submittors' Views
Table A8-18	Ethane Supply and Demand – NEB Projection
Table A8-19	Propane Supply and Demand – NEB Projection
Table A8-20	Butanes Supply and Demand – NEB Projection

Appendix 9

Table A9-1	Historical Data – Coal Production
Table A9-2	Coal Resources and Reserves in Canada
Table A9-3	Coal Production – Canada – Comparison of Submittors' Views
Table A9-4	Primary Demand for Coal – Canada – Comparison of Submittors' Views
Table A9-5	Coal Production – Imports and Exports – NEB Projection

Appendix 10

Table A10-1	Primary Energy Demand – Canada – Comparison of Submittors' Views
Table A10-2	Summary of Total Energy Demand – Canada and Regions
Table A10-3	Total Energy Balance – Canada

Appendix A1-1
List of Submittors

Petroleum Industry

Alberta and Southern Gas Co. Ltd.

Amoco Canada Petroleum Company Ltd.

Canadian-Montana Pipe Line Company

Canadian Petroleum Association

Chevron Canada Ltd.

Cigas Products Ltd.

Consolidated Natural Gas Limited

Dome Petroleum Limited

Gaz Inter-Cité Québec Inc.

Gaz Métropolitain, inc.

Greater Winnipeg Gas Company

Gulf Canada Limited

Husky Oil Operations Ltd./NOVA, AN ALBERTA CORPORATION

Imperial Oil Limited

Inter-City Gas Corporation

Mobil Oil Canada, Ltd.

Pan-Alberta Gas Ltd.

PanCanadian Petroleum Limited

Panarctic Oils Ltd.

Petro-Canada Inc.

Petromont Inc.

Petrosar

Polar Gas Project

Shell Canada Resources Limited

Suncor Inc.

Texaco Canada Inc.

The Consumers' Gas Company Ltd.

TransCanada PipeLines Limited

Trans Québec & Maritimes Pipeline Inc.

Ultramar Canada Inc.

Union Gas Limited

Westcoast Transmission Company Limited

Electric Power

Atomic Energy of Canada Limited

British Columbia Hydro and Power Authority

Electric Utility Planning Council of Alberta

Hydro-Québec

Manitoba Hydro

Maritime Electric Company, Limited

The New Brunswick Electric Power Commission

Northern Canada Power Commission

Ontario Hydro

Major Energy Users

Air Canada

Algoma Steel Corporation, Limited

Canadian Pacific

Cominco Ltd.

Dofasco Inc.

Ethyl Canada

Stelco Inc.

Governments and Agencies

Alberta Energy Resources Conservation Board

Alberta Petroleum Marketing Commission

British Columbia, Ministry of Energy, Mines and Petroleum Resources

Canertech Inc.

Newfoundland and Labrador, Department of Mines and Energy

Province of New Brunswick

Province of Nova Scotia, Department of Mines and Energy

Ontario Ministry of Energy

Quebec, Ministry of Energy and Resources

Saskatchewan Energy and Mines

Associations and Others

Canadian Nuclear Association

Canadian Pulp and Paper Association

Electrical and Electronic Manufacturers Association of Canada

Friends of the Earth

Industrial Gas Users Association

Tidal Power Corporation

Appendix A1-2
Reference Reports

"1977 Northern Pipeline Hearing"	Reasons for Decision – Northern Pipeline In The Matter of the National Energy Board Act; And In The Matter of an application by Canadian Arctic Gas Pipeline Limited for a certificate of public convenience and necessity for the construction and operation of a natural gas pipeline. And In The Matter of applications by Foothills Pipe Lines Ltd., Westcoast Transmission Company Limited and The Alberta Gas Trunk Line (Canada) Limited for certificates of public convenience and necessity for the construction and operation of certain natural gas pipelines: And In The Matter of an application by Alberta Natural Gas Company Ltd. for a certificate of public convenience and necessity for the construction and operation of certain extensions to its natural gas pipeline; And In The Matter of a submission by The Alberta Gas Trunk Line Company Limited; And In The Matter of applications by Foothills Pipe Lines (Yukon) Ltd., Westcoast Transmission Company Limited and The Alberta Gas Trunk Line (Canada) Limited for certificates of public convenience and necessity for the construction and operation of certain natural gas pipelines; And In The Matter of a submission by The Alberta Gas Trunk Line Company Limited – June 1977.
"November 1979 Reasons for Decision"	National Energy Board – Reasons for Decision in the Matter of Applications under Part VI of the National Energy Board Act of Alberta and Southern Gas Co. Ltd., Canadian-Montana Pipe Line Company, Columbia Gas Development of Canada Ltd., Consolidated Natural Gas Ltd., Niagara Gas Transmission Limited, Pan-Alberta Gas Ltd., ProGas Limited, Sulpetro Limited, TransCanada PipeLines Limited, Westcoast Transmission Company Limited, – November 1979
"1981 NEB Report"	Canadian Energy Supply and Demand – 1980-2000 National Energy Board – June 1981
"January 1983 Reasons for Decision" or "1982 Gas Export Omnibus Hearing"	National Energy Board – Reasons for Decisions in the Matter of Phase II – The Licence Phase and Phase III – The Surplus Phase of the Gas Export Omnibus Hearing, 1982 and in the Matter of Applications under Part VI of the National Energy Board Act of Alberta and Southern Gas Co. Ltd., Canadian-Montana Pipe Line Company, Carter Energy Limited, Columbia Gas Development of Canada Ltd., Consolidated Natural Gas Limited, Dome Petroleum Limited, Kanngaz Producers Ltd., Niagara Gas Transmission Limited, Ocelot Industries Ltd., Pan-Alberta Gas Ltd., ProGas Limited, Rim Gas Ltd., Sulpetro Limited, TransCanada Pipelines Limited, TransContinental Gas Pipe Line Corporation, Union Gas Limited, Westcoast Transmission Company Limited, – January 1983

AERCB Report 84-18	Alberta's Reserves of Crude Oil, Oil Sands, Gas, Natural Gas Liquids, and Sulphur at 31 December 1983.
COGLA	1983 Annual Report, Canada Oil and Gas Lands Administration
Data Resources	Canadian Review, Spring 1984, Data Resources of Canada
Informetrica	Workshop 1-84, April 1984, Informetrica
Institute for Policy Analysis	Policy Study No. 84-2, April 1984, Institute for Policy Analysis, University of Toronto
Ontario Ministry of Energy	Potential Demand for Peat, June 1983
	The Homeowner's Off-Oil Heating Conversion Decision, the Costs and Benefits, 1983 Edition
Transport Canada	Transport Canada Freight and Passenger Forecasts – Director General Economic Analysis, Strategic Planning Transport Canada

Appendix A1-3
Abbreviation of Names

"AECL"	Atomic Energy of Canada Limited
"AERCB"	Alberta Energy Resources Conservation Board
"A & S"	Alberta and Southern Gas Co. Ltd.
"Algoma"	Algoma Steel Corporation, Ltd.
"Amoco"	Amoco Canada Petroleum Company Ltd.
"APMC"	Alberta Petroleum Marketing Commission
"B.C."	Ministry of Energy, Mines and Petroleum Resources, Province of British Columbia
"B.C. Hydro"	British Columbia Hydro and Power Authority
"(the) Board" or "NEB"	(the) National Energy Board
"Canadian Montana"	Canadian-Montana Pipe Line Company
"Canertech"	Canertech Inc.
"Chevron"	Chevron Canada Limited
"Cigas"	Cigas Products Ltd.
"CNA"	Canadian Nuclear Association
"COGLA"	Canada Oil and Gas Lands Administration
"Cominco"	Cominco Ltd.
"Consolidated"	Consolidated Natural Gas Limited
"Consumers"	The Consumers' Gas Company Ltd.
"CP"	Canadian Pacific
"CPA"	Canadian Petroleum Association
"CPPA"	Canadian Pulp and Paper Association
"Dofasco"	Dofasco Inc.
"Dome"	Dome Petroleum Limited
"EEMAC"	Electrical and Electronic Manufacturers Association of Canada
"EMR"	Energy, Mines and Resources
"EUPC"	Electric Utility Planning Council of Alberta
"Friends of the Earth" or "Soft Energy Study"	Submission entitled "2025: Soft Energy Futures for Canada"
"GIC"	Gaz Inter-Cité Québec Inc.
"GMi"	Gaz Métropolitain inc.
"GWG"	Greater Winnipeg Gas Company
"Gulf"	Gulf Canada Limited/Gulf Canada Resources Inc.
"Husky"	Husky Oil Operations Ltd.
"Husky/NOVA"	Joint Submission of Husky Oil Operations Ltd. and NOVA, AN ALBERTA CORPORATION
"ICG"	Inter-City Gas Corporation
"IGUA"	Industrial Gas Users Association
"Imperial"	Imperial Oil Limited
"Manitoba Hydro"	The Manitoba Hydro-Electric Board
"Maritime Electric"	Maritime Electric Company Ltd.
"Mobil"	Mobil Oil Canada, Ltd.
"NBEPC"	The New Brunswick Electric Power Commission

"NCPC"	Northern Canada Power Commission
"New Brunswick"	Energy Secretariat, Government of New Brunswick
"Newfoundland"	Department of Mines and Energy, Government of Newfoundland and Labrador
"NOVA"	NOVA, AN ALBERTA CORPORATION
"Nova Scotia"	Department of Mines and Energy, Province of Nova Scotia
"Ontario"	Ministry of Energy, Province of Ontario
"OPEC"	Organization of Petroleum Exporting Countries
"Pan-Alberta"	Pan-Alberta Gas Ltd.
"Panarctic"	Panarctic Oils Ltd.
"Pan Canadian"	PanCanadian Petroleum Limited
"Petro-Canada"	Petro-Canada Inc.
"Petromont"	Petromont Inc.
"Petrosar"	Petrosar Limited
"Polar"	Polar Gas Project
"ProGas"	ProGas Limited
"Quebec"	Ministère de l'Energie et des Ressources, Gouvernement du Québec
"Saskatchewan"	Saskatchewan Energy and Mines
"Shell"	Shell Canada Limited/Shell Canada Resources Limited
"Stelco"	Stelco Inc.
"Suncor"	Suncor Inc.
"Syncrude"	Syncrude Canada Ltd.
"TCPL"	TransCanada PipeLines Limited
"Texaco"	Texaco Canada Inc.
"Tidal"	Tidal Power Corporation
"TQM"	Trans Quebec & Maritimes Pipeline Inc.
"Ultramar"	Ultramar Canada, Inc.
"Union"	Union Gas Limited
"WTCL"	Westcoast Transmission Company Limited

Abbreviation of Terms

API	American Petroleum Institute
BER	Beyond Economic Reach
EOR	Enhanced Oil Recovery
GNP	Gross National Product
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gases
NEP	National Energy Program
NGL	Natural Gas Liquids
NGV	Natural Gas for Vehicles
RDP	Real Domestic Product

Appendix A1-4 Definitions

°API – Degree(s) API	A relative measure of the specific gravity of crude oils. Crude oils with a higher value of °API have a lower specific gravity.
Associated Gas	Natural gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir.
Base Load Capacity	Electricity generating equipment which operates to supply the load over most hours of the year.
Beyond Economic Reach Reserves	Established reserves, which because of size, location or composition are not considered economically viable at the present time.
Biomass	Organic material such as wood, crop waste, municipal solid waste and mill waste, processed for energy production.
Bitumen	See 'Crude Bitumen'
Blowdown	The production of gas, either from the gas cap of an oil reservoir, normally after depletion of the oil, or from a cycled gas pool upon cessation of the cycling operation.
Capacity Available (Electricity)	The sum of the Installed Capacity in a system plus firm purchases.
Capacity (Electricity)	The maximum amount of power which a machine, apparatus or appliance can generate, utilize or transfer, expressed in kilowatts or some multiple thereof.
Carbon Dioxide (CO_2) Flooding	An enhanced recovery process in which carbon dioxide is injected into an oil reservoir to increase recovery.
Chemical Flooding	An enhanced recovery process in which water, with added chemicals, is injected into an oil reservoir to increase recovery.
Coal Gasification	The production of a synthetic natural gas from coal.
Coal Liquefaction	The production of a synthetic crude oil or related liquid fuel from coal.
Co-generation	A facility which produces steam heat as well as electricity with a resultant overall improvement in energy conversion efficiency.
Condensate	As used in this report, synonymous with pentanes plus.
Conventional Areas	Generally, the Western Provinces, Southwestern Ontario, and the southern part of the Yukon and Northwest Territories.
Conventional Producing Areas	Same as 'Conventional Areas'

Crude Bitumen	A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and other minerals, and that in its natural viscous state is not recoverable at a commercial rate through a well.
Crude Oil and Equivalent Hydrocarbons	Sometimes referred to as 'Crude Oil and Equivalent'. Includes light and heavy crude oil, pentanes plus and synthetic crude oil.
Deferred Reserves	Established natural gas reserves which for a specific reason, usually because of involvement in a recycling or pressure maintenance project, are not currently available to a market.
Deliverability	A general term used to refer to the ability of a well, pool or other entity to produce natural gas.
Electricity Production	The process of generating electric energy. In this report it includes the amount of such energy, expressed in kilowatt hours or multiples of kilowatt hours, that individual generating units or groups of generating units can reasonably be expected to produce in a year. The determination of electric energy production takes into account various factors such as the type of service for which generating units were designed (e.g., peaking or base load) the availability of fuels, the cost of fuels, river water levels, and environmental constraints.
End Use Demand for Energy (or Secondary Energy Demand)	Energy used by final consumers for residential, commercial, industrial and transportation purposes, and hydrocarbons used for such non-energy purposes as petrochemical feedstock.
Energy Intensity	In the industrial and commercial sectors and in transportation other than automobiles energy intensity is defined as the amount of energy per unit of production. In the residential sector it is energy use per household and for automobiles it is energy use per car. A measure of the efficiency with which energy is used in the economy as a whole is total end use energy per unit of GNP.
Enhanced Oil Recovery (or Enhanced Recovery)	See 'Recovery – Enhanced'
Established Reserves	Those (oil and gas) reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that judgment portion of contiguous recoverable reserves that is interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.
Experimental Crude Oil	Crude oil produced from pilot projects designed to investigate new recovery techniques.
Export of Electricity	Transfer of power or energy from a utility system in Canada to another in the United States. Such export requires NEB approval.
Feedstock	Raw material supplied to a refinery or petrochemical plant.

Firm Power	Electric power intended to be available at all times during the period covered by an agreement.
Flat Life	That period of the producing life of a resource during which production is maintained at a constant rate.
Frontier Areas	Generally, the northern and offshore areas of Canada.
Fuel Efficiency (Burner Tip Efficiency)	The ratio of the useful output energy which results when a fuel is burned, to the theoretical input energy content of the fuel. Fuel efficiency for a heating fuel is less than 100 percent to the extent that heated air is used in combustion and to the extent that exhaust venting is necessary. In other applications fuel efficiencies are less than 100 percent partly because of waste heat generation.
Gas Cycling Scheme	A scheme in which part or all of the produced natural gas is reinjected into the reservoir after removal of natural gas liquids.
Heavy Crude Oil	A term applied to crude oil having a high density. Appendix A7-5 shows production from the crude streams which are included in the NEB's heavy crude category.
Heavy Fuel Oil	In this report the term heavy fuel oil is used to include bunker fuel oils (No. 5 and No. 6 fuel oils) and industrial fuel oil (No. 4 fuel oil).
Hog Fuel	Fuel consisting of bark, shavings, sawdust, low grade lumber and lumber rejects from the operation
Hybrid System	A dual fuel heating system using two alternative sources of energy. The most common systems use oil and electricity.
Hydroelectric Generation	An electric generator driven by a hydraulic turbine.
Infill Drilling	The process of drilling additional wells within the defined pool outline of a natural gas or oil pool.
Initial Established Reserves	Established reserves prior to the deduction of any production.
In Situ Recovery	The process of recovering crude bitumen from oil sands other than by surface mining.
Interruptible Power	Electric power and/or energy made available under an agreement that permits curtailment or cessation of availability at the option of the supplier.
Light Crude Oil	A term applied to crude oil having a low density. Appendix A7-5 shows production from the crude streams which are included in the NEB's light crude category.
Light Fuel Oil	In this report the term light fuel refers to furnace fuel oil (No. 2 fuel oil), kerosene and stove oil (No. 1 fuel oil). The major volume of light fuel oil used in Canada is furnace fuel oil.

Liquefied Petroleum Gases (LPG)	As used in this report, the term refers to the hydrocarbons propane and butanes, or combinations thereof
Load Factor	The ratio of the average load over a designated period of time to the maximum load occurring in that period, expressed in percent.
Marketable Natural Gas	Natural gas which meets specifications for end use.
Middle Distillates	The range of refined petroleum products which includes kerosene, stove oil, diesel fuel, and light fuel oil.
Miscible Flooding	An enhanced recovery process in which a fluid, capable of mixing completely with the oil it contacts, is injected into an oil reservoir to increase recovery.
Natural Gas Liquids (NGL)	The hydrocarbons, ethane, propane, butanes, and pentanes plus or a combination thereof.
Non-Associated Gas	Natural gas not in contact with crude oil in the reservoir.
Non-Conventional Generation	The generation of electricity by any means other than hydroelectric generation, thermal generation using nuclear fuel, coal, oil or natural gas, gas turbine generation using oil and natural gas, or internal combustion generation. Examples would be solar power and wind energy.
Oil Sands	Deposits of sand or sandstone, or other sedimentary rock containing crude bitumen.
Peak Demand (Electricity)	The highest level of power demand by customers on a power system within a specified period, usually a year, (i.e., on a major utility, a minor utility or an individual industry generating its own electricity). The peak demand is measured in kilowatts or multiples of kilowatts.
Peaking Capacity	Electricity generating equipment which is available to meet that portion of the load which occurs for only a few hours during the day.
Pentanes Plus	A liquid composed primarily of pentanes and heavier hydrocarbons.
Permeability	A measure of the capacity of a reservoir rock to transmit fluids.
Plasma Arc Technology	Use of electrical arcs in a plasma furnace to efficiently produce very high temperatures for applications such as metal melting and coating, and industrial drying.

Primary Energy Demand	Represents the total requirement for all uses of energy in Canada, including energy used by the final consumer, intermediate uses of energy in transforming one energy form to another (e.g. coal to electricity), and energy used by suppliers in providing energy to the market (e.g. pipeline fuel). By definition: Primary energy demand = end use energy demand + energy supply industry use − electricity and steam demand + energy used to generate electricity and produce steam + other conversion losses See Chapter 10 for a discussion of the methods used to calculate primary energy demand.
Primary Recovery	See 'Recovery – Primary'
Productive Capacity	The estimated rate at which crude oil or crude bitumen can be produced from a well, pool or other entity, unrestricted by demand, having regard to reservoir characteristics, economic considerations, regulatory limitations, the feasibility of infill drilling, the availability of gathering, processing and transmission facilities, and potential losses due to mechanical breakdown.
Pulping Liquor (also known as waste liquor or black liquor)	A substance primarily made up of lignin, other wood constituents, and chemicals which are by-products of the manufacture of chemical pulp. It can be burned in a boiler to produce steam or electricity, through thermal generation.
Rate of Take	The average daily rate of production of natural gas related to the volume of initial established reserves assigned to the reservoir or reservoirs from which the production is obtained. For example, 1:7300 means one unit of production a day for each 7300 units of initial established reserves.
Raw Natural Gas	Unprocessed natural gas.
Recovery – Primary	The volume of crude oil recoverable from a reservoir through natural depletion processes only.
– Secondary	The incremental volume of crude oil recoverable from a reservoir through the utilization of a pressure maintenance scheme such as waterflooding or gas injection.
– Tertiary	The incremental volume of crude oil recoverable from a reservoir other than through natural depletion and pressure maintenance processes.
– Enhanced	The incremental volume of crude oil recoverable from a reservoir through a production process other than natural depletion; the production process used to achieve such incremental volume. Enhanced recovery includes both secondary and tertiary recovery.

Refinery Acquisition Cost	The delivered price of crude oil to a refinery, including all transportation charges to that point, the Petroleum Compensation Charge and the Canadian Ownership Special Charge.
Remaining Capacity (Electricity)	The difference between Capacity Available and the System Peak Demand. The remaining capacity includes the margin of capability available to provide for scheduled maintenance, emergency outages, system operating requirements and unforeseen loads. On a national basis it is the difference between the aggregate net Capacity Available of the various systems in Canada and the sum of the System Peak Demands, without allowance for time diversity between the loads of the several systems.
Remaining Established Reserves	Initial established reserves less cumulative production.
Reserves Additions	Incremental changes to established reserves resulting from the discovery of new pools and reserves appreciation.
Reserves Appreciation	Incremental change in established reserves resulting from extensions to existing pools and/or revisions to previous reserves estimates.
Reserves Life Index	Remaining reserves divided by annual production.
Secondary Recovery	See 'Recovery – Secondary'
Shut-in Capacity	The unused productive capacity of an oil or gas pool or area.
Social Supply Cost	The sum of capital and operating costs per unit of production, exclusive of royalties, taxes, subsidies, or incentive payments, discounted at a real rate of ten percent, the estimated social opportunity cost of capital in Canada.
Solar Energy – Active System	Solar energy collection systems which transfer heat captured from solar radiation through mechanical devices.
Solar Energy – Passive System	Solar energy collection systems which capture solar radiation directly for space heating, water heating or other similar purposes, without the use of mechanical devices.
Solution Gas	Natural gas in solution with crude oil in the reservoir at original reservoir conditions and which is normally produced with the crude oil.
Solvent Flooding	See 'Miscible Flooding'
Straddle Plant	A natural gas processing plant, located on a main gas transmission system, which extracts NGL from the gas stream.
Supply Capability	The estimated rate at which natural gas, under standard conditions of temperature and pressure, can be produced from a well, pool or other entity, unrestricted by demand, having regard to reservoir characteristics, economic considerations, contractual and regulatory limitations, the feasibility of infill drilling and/or addition of compression, the availability of processing facilities and potential losses due to mechanical breakdown.

Synthetic Crude Oil	Crude oil resulting from the processing of crude bitumen, coal or wood.
Synthetic Natural Gas (SNG)	Natural gas produced from petroleum liquids, coal or wood.
Tertiary Recovery	See 'Recovery – Tertiary'
Thermal Generation	Energy conversion in which fuel is consumed to generate heat energy which is converted to mechanical energy and then to electricity in a generator. Normally, the fuel may be coal, oil, gas, or uranium (nuclear).
Thermal Processes	Enhanced oil recovery processes in which heat is added to the reservoir to increase recovery.
Thermo-Mechanical Pulping Process (TMP)	Electrically produced mechanical energy is used to refine steamed wood chips into pulp. Recovered steam may be used for space heating or for drying pulp fibres.
Transfer Capability	The overall capacity of interprovincial or international power lines, together with the associated electrical system facilities, to transfer power and energy from one electrical system to another.
Transmission	The movement or transfer of electricity from one point to another in a power system and between systems.
Ultimate Potential	An estimate of the initial established reserves which will have become developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of the area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves and future additions through extensions and revisions to existing pools and the discovery of new pools.
Waterflooding	An enhanced recovery process in which water is injected into an oil reservoir to increase recovery.
Wellhead	Specifically, the equipment at the top of a well for maintaining control of the well. More generally, it is used to specify a reference or delivery point on the production system.
World Oil Price	As used in this report, the term refers to the official selling price of OPEC's marker crude oil (Saudi Arabian Light 34°API).
Wood Gasification	The production of a synthetic natural gas from wood.
Wood Liquefaction	The production of liquids (e.g. methanol) from wood.

Wood Waste — Fuel consisting of bark, shavings, sawdust and low grade lumber and lumber rejects from the operation of pulp mills, sawmills and plywood mills.

Wood Wastes — Refers to wood waste and pulping liquor.

Appendix A1-5
Conversion Factors

Prefixes

Prefix	Multiple	Symbol
kilo-	10^3	k
mega-	10^6	M
giga-	10^9	G
tera-	10^{12}	T
peta-	10^{15}	P
exa-	10^{18}	E

Imperial Equivalent Units

Metric	Imperial
1 cubic metre of oil	
(15°C and 922 Kg/m^3)	= 6.292 26 barrels (60°F and 22°API)
(15°C and 855 Kg/m^3)	= 6.292 58 barrels (60°F and 34°API)
(15°C and 739 Kg/m^3)	= 6.294 03 barrels (equilibrium pressure, 60°F and 60°API)
1 cubic metre of natural gas (101.325 kilopascals and 15°C)	= 35.301 01 cubic feet (14.73 psia and 60°F)
1 cubic metre of ethane (equilibrium pressure and 15°C)	= 6.330 barrels of ethane (equilibrium pressure and 60°F)
	= 9.930 thousand cubic feet of ethane gas (14.73 psia and 60°F)
1 cubic metre of propane (equilibrium pressure and 15°C)	= 6.300 0 barrels of propane (equilibrium pressure and 60°F)
1 cubic metre of butanes (equilibrium pressure and 15°C)	= 6.296 8 barrels of butanes (equilibrium pressure and 60°F)
1 tonne	= 1.102 311 tons
1 kilojoule	= 0.948 213 3 British thermal units (Btu)

Gross Energy Content Factors

Natural Gas		
B.C. - domestic	39.10	MJ/m^3
- Huntingdon	39.10	MJ/m^3
- Kingsgate	37.65	MJ/m^3
- Grassy Point	38.20	MJ/m^3
Alberta - domestic	38.80	MJ/m^3
- Cardston	37.65	MJ/m^3
- Aden	36.06	MJ/m^3
East of Alberta	37.65	MJ/m^3
Ethane (liquid)	18.36	GJ/m^3
Propane (liquid)	25.53	GJ/m^3
Butanes (liquid)	28.62	GJ/m^3
Crude Oil		
Light and Medium	38.51	GJ/m^3
Heavy	40.90	GJ/m^3
Pentanes Plus	35.17	GJ/m^3
Coal		
Bituminous	29.30	GJ/tonne
Sub-Bituminous	19.76	GJ/tonne
Lignite	15.35	GJ/tonne
Average domestic use	24.00	GJ/tonne
Petroleum Products		
Aviation Gasoline	33.52	GJ/m^3
Motor Gasoline	34.66	GJ/m^3
Petrochemical Feedstocks	35.17	GJ/m^3
Naphtha Specialties	35.17	GJ/m^3
Aviation Turbo	35.93	GJ/m^3
Kerosene	37.68	GJ/m^3
Diesel	38.68	GJ/m^3
Light Fuel Oil	38.68	GJ/m^3
Lubes and Greases	39.16	GJ/m^3
Heavy Fuel Oil	41.73	GJ/m^3
Still Gas	41.73	GJ/m^3
Asphalt	44.46	GJ/m^3
Petroleum Coke	42.38	GJ/m^3
Other Products	39.82	GJ/m^3
Electricity		
Secondary	3.6	MJ/kwh
Primary	10.5	MJ/kwh

Appendix A1-6

File No.: 1071-3

14 October 1983

To: Interested Parties

Re: *NEB Update of Energy Supply and Demand, 1983 to 2005*

From time to time, the National Energy Board publishes reports outlining the prospects for the supply of and demand for major forms of energy in Canada. The latest of these reports was completed in June, 1981 following a public inquiry into the subject.

The Board does not intend to hold another public inquiry at this time. However, in light of the significant changes that have taken place in domestic and international energy markets in the last two years, an update of the 1981 projections appears desirable. The Board has therefore decided to have its staff conduct an update and produce a report thereon. In order to expedite and simplify the process, the Board concluded that rather than initiating time-consuming public hearings, it would be preferable in the circumstances for the views of interested parties to be submitted directly to NEB staff to provide a foundation for its update of the energy supply and demand outlook.

This letter is being sent to request your participation in the update. Since we plan to complete the study and publish a staff report by early summer of 1984, we are requesting that your written submission be provided no later than 16 January 1984. You are encouraged to contact Board staff at any time during the update process for further clarification, guidance or discussion. Your submission will be reviewed by Board staff and discussed as required with you early in 1984.

Preparing a reliable long-term energy forecast at this time is particularly difficult: it is unclear when and to what extent the major industrial economies will emerge from the deepest recession of the post-war period; there is considerable uncertainty with respect to the prospective path of world oil prices; and, because adaptation to the enormous energy price increases of the 1970s is still going on, it is far from clear to what extent the recently-observed decline in demand for energy is related to the decline in economic activity, to the price increases of the 1970s or to other factors. Accordingly we think it appropriate to attempt to undertake an assessment of the uncertainties associated with the outlook for energy supply and demand. Specifically, we seek your analysis and informed opinion regarding:

1. the most plausible outlook for energy supply and demand in Canada to the year 2005;
2. the effect on your forecast of alternative energy price and economic growth assumptions; and
3. certain issues which the Board staff believes have particular importance in shaping supply and demand estimates in today's environment.

A detailed outline of the issues as we see them and our proposed methods of conducting the study are contained in the attached guidelines. Your written submission and subsequent exchange of views will assist Board staff in examining these complex matters.

All submissions will be considered public documents and will be available for review in the library of the National Energy Board, 473 Albert Street, Ottawa, and at the Board's Calgary office, 4500-16 Avenue N.W. Submittors are not required to serve copies of their submission on other parties but are requested to provide 20 copies to Board staff via the Office of the Secretary. In the case of technical material pertaining to petroleum supply, 5 copies will suffice. We would appreciate an early indication of your intention to participate in this update.

Yours truly,

G. Yorke Slader,
Secretary

List of Parties Who Have Been Invited to Provide Submissions to NEB Update of Energy Supply and Demand, 1983 to 2005

Petroleum Industry

Alberta and Southern Gas Co. Ltd.
Amoco Canada Petroleum Company Ltd.
ATS Exploration Limited
B.P. Canada Inc.
B.P. Exploration Canada Limited
Canadian Gas Association
Canadian Hunter Exploration Ltd.
Canadian-Montana Pipe Line Company
Canadian Petroleum Association
Canadian Western Natural Gas Company Limited
Canterra Energy Ltd.
Chevron Canada Ltd.
Chevron Standard Ltd.
Cigas Products
Columbia Gas Development of Canada Ltd.
Consolidated Natural Gas Limited
Consumers Co-operative Refineries Ltd.
Dome Petroleum Limited
Esso Resources Canada Limited
Gaz Inter-Cité Québec Inc.
Gaz Métropolitain, inc.
Gulf Canada Limited,
Gulf Canada Resources, Inc.
Home Oil Company Limited
Husky Oil Operations, Limited
Imperial Oil Limited,
Independent Petroleum Association of Canada
Inter-City Gas Corporation
Irving Oil Company
KannGaz Producers Ltd.
Mobil Oil Canada, Ltd.
Murphy Oil Company Ltd.
Niagara Gas Transmission Limited
Norcen Energy Resources Limited
Northwestern Utilities
NOVA, AN ALBERTA CORPORATION
Ocelot Industries Ltd.
Pan-Alberta Gas Ltd.
PanCanadian Petroleum Limited
Panarctic Oils Ltd.
Petro-Canada Inc.
Petromont Inc.
Petrosar
Polar Gas Project
ProGas Limited
Propane Gas Association of Canada Inc.
Ranchmen's Resources (1976) Ltd.
Shell Canada Limited
Shell Canada Resources Ltd.
Société Québecoise d'initiatives pétrolières (SOQUIP)
Sulpetro Limited
Suncor, Incorporated
Texaco Canada, Incorporated
The Consumers' Gas Company Ltd.
TransCanada PipeLines Limited
Turbo Resources Limited
Ultramar Canada, Incorporated
Union Carbide Canada Limited
Union Gas Limited
Westcoast Transmission Company Limited

Associations and Other

Association of Major Power Consumers in Ontario
Canadian Arctic Resources Committee
The Canadian Chemical Producers Association
Canadian Electrical Association
Canadian Energy Research Institute
Canadian Federation of Agriculture
Canadian Fertilizer Association
Canadian Motor Vehicles Manufacturers' Association
Canadian Nuclear Association
Canadian Pulp & Paper Association
Canadian Solar Industries Association Inc.
Canadian Trucking Association
The Coal Association of Canada
Consumers' Association of Canada
Council of Forest Industries of British Columbia
Electrical and Electronic Manufacturers Association of Canada
Energy Probe
GAMMA Institute
Housing and Urban Development Association of Canada (HUDAC)
Industrial Gas Users Association

Electric Power

Abitibi-Price Inc.
Alberta Power Limited
Algoma Steel Corporation, Ltd.
British Columbia Hydro and Power Authority
Canadian Utilities Limited
Cominco Ltd.
Edmonton Power
Fraser Inc.
Great Lakes Power Co.
Hydro-Québec
The Manitoba Hydro-Electric Board
Maritime Electric Company Ltd.
The New Brunswick Electric Power Commission
Newfoundland and Labrador Hydro
Newfoundland Light & Power Company Limited
Northern Canada Power Commission
Nova Scotia Power Corporation
Ontario Hydro
Saskatchewan Power Corporation
TransAlta Utilities Corporation

Major Energy Users

Air Canada
Alcan Aluminum Ltd.
Canada Cement Lafarge Ltd.
Canadian Industries Ltd. (C-I-L Inc.)
Canadian International Paper Inc. (CIPINC)
Canadian Pacific Ltd.
Cynamid Canada (Inc.)

Dofasco Inc.
Ethyl Canada
Irving Pulp and Paper Ltd.
McMillan and Bloedel Limited
Noranda Mines Ltd.
Stelco Inc.

Governments and Agencies

Province of British Columbia
  Minister of Energy, Mines and Petroleum Resources
Province of Alberta
  Alberta Energy Resources Conservation Board
  Alberta Petroleum Marketing Commission
  Alberta Energy and Natural Resources
Province of Saskatchewan
  Minister of Mineral Resources
Province of Manitoba
  Minister of Energy and Mines
Province of Ontario
  Ministry of Energy
Province of Quebec
  Ministère de l'énergie et des ressources
  Procureur général du Québec
Province of New Brunswick
  Minister Responsible for Energy Policy
  Energy Secretariat
Province of Nova Scotia
  Minister of Mines and Energy
Government of Newfoundland and Labrador
  Minister of Mines and Energy
Province of Prince Edward Island
  Energy and Mineral Resources

1984 Supply and Demand Update Guidelines for Submission

Introduction

The staff of the National Energy Board is preparing updated projections of the supply of and demand for domestic energy to the end of 2005. On the supply side, the update will include crude oil, natural gas, natural gas liquids, electricity and other forms of energy such as coal, wood waste, pulping liquor and solar. On the demand side, the update will deal with refined petroleum products, refinery feedstocks, natural gas, liquefied petroleum gases, electricity, coal and coke and other energy forms.

To supplement its own work, the NEB staff is interested in the forecasts, views and analyses of other members of the energy forecasting community. To this end, submittors who provided supply and demand estimates to the Board's 1981 Energy Inquiry and other selected parties are being invited to provide written submissions, by 16 January 1984. To provide for some analysis, submittors are requested to follow as closely as possible the instructions contained in these guidelines when preparing their submissions.

Essentially, we are interested in obtaining the views of interested parties as to the most plausible outlook for energy supply and demand in Canada to the year 2005. To the extent possible, we would like to be able to determine the factors that contribute to differences in the projections of different submittors. Moreover, because of the uncertainties confronting the Canadian and world economics in general and the energy sector in particular, we are also interested in assessing the impact on the energy supply and demand outlook of alternative price and output assumptions. In addition, certain issues have been identified by Board staff as having a special importance in formulating the projections. Your comments on these issues, which are listed in the relevant sections, would be especially appreciated.

The following sections outline those matters on which Board staff would like to receive your views and indicate the manner in which they should be presented:

Section A: General Underlying Assumptions
Section B: Domestic Demand for Energy
Section C: Domestic Supply Capability
Section D: Supply/Demand Balances
Section E: Preferred Format for Presentation of Data

A. General Underlying Assumptions

Projections are heavily dependent on a number of key assumptions, particularly about world oil prices, the level of economic activity and the domestic energy policy regime. Since these assumptions will vary by submittor, it is critical that they be specified in detail.

In addition to your most plausible outlook for future supply and demand, we would like to receive views on the sensitivity of your forecast to alternative energy prices. Analysts examining the prospects for world oil prices are increasingly of the view that prices in real

terms will remain relatively constant or follow a growth path of the order of 1 or 2 per cent per year for the rest of the century. On the other hand, there is recognition, particularly among political analysts, that there is considerable risk of further oil price shocks over the next decade as a result of political instability in the oil exporting countries. We intend, therefore, to assess the impact on the Canadian energy sector of two energy price scenarios reflecting these views. Possible representations of high and low price scenarios are shown in Figure 1. We would encourage submittors to provide us with their views on the impact of these two scenarios on their energy supply/demand projections.

With respect to the prospects for growth in Gross National Product (GNP), many analysts are currently assuming a path which implies significant excess capacity and relatively high unemployment throughout the 1980s and into the 1990s. While this may be viewed as a reasonable assumption in outlining a most likely growth path, it would be useful to assess the impact of faster GNP growth on the energy sector. For this purpose, we are proposing that submittors assess, relative to their current projections, the implications for supply and demand of a GNP growth path in which real GNP grows at an average rate of 4.5 per cent per year in 1984 through 1988 and 3.0 per cent per year thereafter to the year 2005.

A projection of energy supply and demand will obviously be critically influenced by the assumptions made with respect to the domestic energy policy environment. In the absence of other information at this time, Board staff will be making its projections on the conventional assumption that the currently existing policy regime will remain in force throughout the projection period. If you make your projections on the basis of different assumptions, we would appreciate having your views on the effect that continuation of the current policy regime would have on your energy supply and demand projections.

Years	High Price Scenario	Low Price Scenario
1982	34.00	34.00
1983	28.30	28.30
1984	26.50	26.50
1985	33.00	26.50
1986	38.00	26.50
1990	40.00	26.50
1995	42.00	26.50
2000	44.00	26.50
2005	46.00	26.50

B. Demand

As Board staff intends to publish an estimate of demand for all major forms of energy in Canada, submittors are encouraged to provide a breakdown of Canadian energy demand by energy type for the various sectors and regions using the format outlined in Appendix 1. We recognize, however, that many submittors may prefer to submit a forecast for only a part of the total energy spectrum – for selected energy forms, for a specific market area, or for a specific market type – and all such specialized forecasts will be welcome.

All assumptions and methodology should be described in sufficient detail to permit a general understanding of how the forecast was assembled. However, certain matters have been singled out by Board staff as being of special interest in the context of the current update and we would appreciate detailed analysis and comments on these issues.

Issues

B.1 The extent to which the decline in energy demand in recent years has been related to the decline in economic activity resulting from the recession, to a delayed response (by means of conservation) to the large price increases of the 1970s or to other factors.

B.2 The prevalence of and prospects for dual-fuel capability in the industrial sector and for hybrid systems (e.g., electricity-oil) and heat pumps in the residential sector.

B.3 The extent to which the shift toward smaller, fuel-efficient cars will be reversed by lower than expected gasoline prices.

B.4 The level of substitution for motor gasoline by alternative transportation fuels such as diesel fuel, NGV (natural gas for vehicles), propane, methanol, hydrogen and electricity.

B.5 The prospects for rail electrification, and for increased use of electricity in intra-urban road transportation.

B.6 The impact of technological change on energy demand through such factors as improved furnace efficiencies, changing industrial processes, improved automobile and truck fuel efficiencies, and modification of aircraft engines.

B.7 How the changing industrial structure (e.g., changes in product mix, growth of high-technology industries) will affect energy demand.

B.8 The prospects for electricity prices and the implications thereof on the degree of interfuel competition between natural gas and electricity, particularly in Ontario and Quebec (TCPL Eastern Zone), and in British Columbia.

B.9 The impact of electricity exchange between regions on the demand for other fuels.

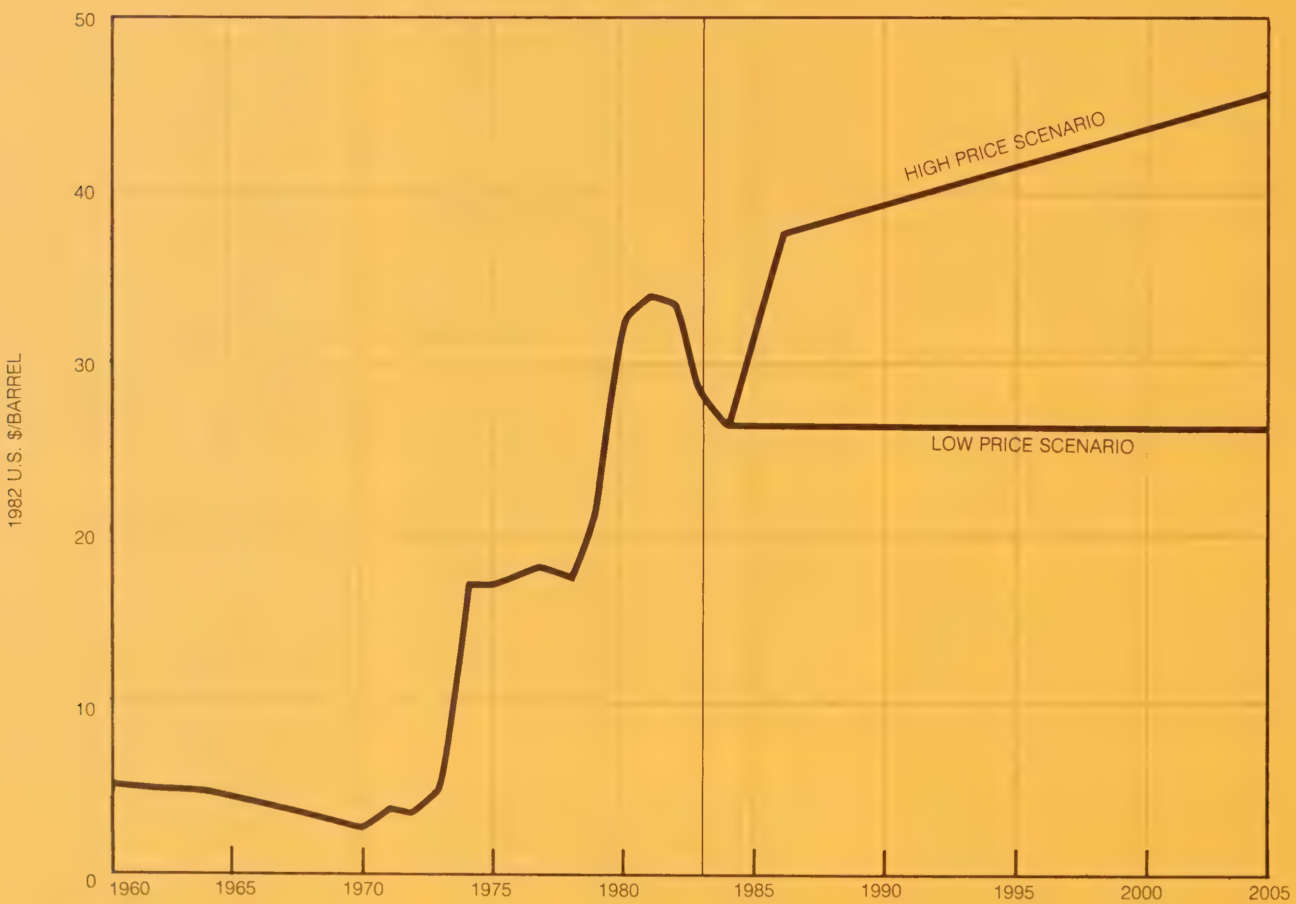
B.10 The competition in the industrial sector between heavy fuel oil and other energy forms.

B.11 The potential for natural gas use in new geographic and industrial markets (e.g., Vancouver Island, Maritimes, direct sales).

C. Supply

In this aspect of the review, Board staff wishes to obtain information concerning Canada's total energy supply. It is not considered likely that conventional natural gas deliverability from non-frontier areas has changed significantly since the Board's 1982 Gas Export Omnibus Hearing. Accordingly, detailed reservoir data with respect to natural gas reserves and deliverability for the non-frontier areas are not formally requested at this time although any such data are always welcome and will be incorporated into the current update. However, we are specifically

Figure 1
PRICE SCENARIOS TO BE ASSESSED
Official Price of Arab Light 34° API
(1982 U.S. Dollars per Barrel)



requesting detailed current information relevant to the supply of oil from both the frontier and non-frontier areas, the supply of natural gas from the frontier areas and the supply from all energy forms other than oil and gas. The catagories of supply for which information is sought are listed in Appendix 2.

With respect to the effect of economics on supply, staff is most interested in receiving views on the price, netbacks and other economic conditions needed to bring new energy projects into being, and the effect of the two alternative energy price scenarios on major new energy supply projects.

Opinion is sought on expected netbacks and the likely impact of the domestic energy pricing, taxation and subsidy regime on oil and gas exploration and development. As well, information on reserves and expected dates of commencement of production from oil and gas pools discovered in the frontier areas would be particularly welcome. Operators and major interest owners of frontier pools are urged to provide as much information on the subject as possible in order that a realistic assessment of future frontier supply can be made. We would appreciate your views regarding the problems and concerns envisaged with respect to such matters as project timing, economic factors and market opportunities.

Oil Supply Issues

C.1 Whether the current emphasis on oil-directed drilling, and oil well workovers is expected to result in significantly higher levels of reserves additions and future productive capacity than forecast previously by the industry.

C.2 The contribution of enhanced recovery projects to reserves additions and productive capacity for both the light and medium, and heavy crude oil categories.

C.3 The factors necessary to sustain the recent significant increases in the production of heavy crude oil.

C.4 Whether there will be sufficient condensate available to use as a diluent for the movement of heavy crude oils as well as for other purposes such as refinery feedstock, petrochemical feedstock and enhanced oil recovery.

C.5 The impact of limited condensate supply on bitumen type projects and on conventional heavy crude oil production.

C.6 The future availability of heavy crude oil and upgraded heavy crude oil from oil sands, and the desirability of the trend toward smaller scale projects.

C.7 The conditions required to make economically viable the upgrading of heavy crude oil for use as a domestic feedstock.

C.8 The likelihood of discovering and/or developing commercially recoverable oil reserves in the frontier areas, the probable timing of development, and levels of production.

Natural Gas Supply Issues

C.9 The current excess deliverability of natural gas and ways of managing or reducing it (e.g., gas storage, prorationing, incentive marketing).

C.10 The long-term effects on exploration, development and resource recovery of such factors as prolong weak demand, contractual abrogations and reduced producer netbacks.

C.11 The likelihood and timing of the development of commercial natural gas reserves in frontier areas and the probable level of output from these reserves.

C.12 New concepts or probable developments with respect to non-conventional (very low permeability) reservoirs.

Natural Gas Liquids Supply Issues

C.13 The effect of the requirement for NGL for enhanced recovery projects on the available supply of ethane, propane and butanes.

C.14 The effects of the reduced production of natural gas and reduced refinery throughput on the availability of NGL.

C.15 Expected trends in NGL yields from natural gas reserves additions.

Electric Power Generation Issues

C.16 The likely role of nuclear generation in future domestic supply.

C.17 The potential for development of additional hydroelectric generating plants.

C.18 The role and significance of current and future industrial generation capability.

C.19 The effect of tighter air quality emission standards and any other regulatory restrictions on electric power generation.

C.20 The role of Western coal in electric power generation.

Issues Relating to Other Energy Forms

C.21 The expected contribution to energy supply of other forms of energy such as coal, wood and wood products, pulping liquor, alcohol, biomass, solar, wind and tidal power.

D. Supply/Demand Balances

Submittors are encouraged to provide supply/demand balances for those energy forms for which they have prepared forecasts of supply and demand. In estimating the levels of supply of hydrocarbons and electricity within these supply/demand balances, submittors are asked to take expected imports into account. In estimating the levels of demand for hydrocarbons and electricity, submittors are also requested to take account of authorized and expected exports.

Issues

D.1 The prospects for Canadian energy self-sufficiency over the period of the forecast, with particular emphasis on light and medium crude oil.

D.2 The continued availability and magnitude of an export market for heavy crude oil and factors which may enhance or restrict that market.

D.3 The likely short-term market for Canadian gas in the United States, with a particular assessment of the effect of possible deregulation of the price of natural gas in the United States and the consequent competitive position of Canadian natural gas in relation both to U.S. gas and residual fuel oil.

D.4 The likely level of exports of electricity to the United States and the expected selling price; in particular, any information on the future trend of the price of coal in the U.S. and its relationship to the price of oil.

E. Preferred Format for Presentation of Data

We appreciate that many submittors may have developed formats for presentation of supply and demand data for their own purposes, and we are prepared to receive data in that form. However, for those submittors providing highly disaggregated information, our work will be greatly facilitated by the use of standard forms similar to those used for submissions to the Board's 1981 Energy Inquiry. For copies of these standard forms, please contact the Secretary of the Board. The forms available are listed in Appendix 3.

Board staff will be in contact with submittors to discuss the most expeditious method of obtaining data to update crucial parts of our forecast such as those involving oil supply by pool, NGL supply by plant, and electric power generation by province.

In order that the forecasts can be compared, submittors are requested to specify the assumptions they have made with respect to such matters as economic growth, population growth, world oil prices, relative prices of various types of energy, taxes and royalties, and any other assumptions that significantly affect the forecast.

It is requested that actual supply and demand data be provided for 1982 and forecasts be provided for the years 1983 through 1987, and for 1990, 1995, 2000 and 2005.

General questions on the conduct of the update should be directed to Mr. Ken Vollman, Director General Energy Studies ((613) 995-5779) who will be coordinating the staff report. Questions and comments relating to specific areas may be directed to appropriate Board staff members as follows:

	Telephone No.
Demand for all forms of energy. – Heather Webster, Economics Branch	(613) 996-7572
Supply of natural gas – Ken Poole, Energy Supply Branch	(613) 996-2720
Supply of oil, natural gas liquids, and other forms of energy except electricity and natural gas – Gerrit Hos, Energy Supply Branch	(613) 996-2344
Supply, demand and exports of electricity. – Bill Correll, Electric Power Branch	(613) 593-6185
Exports and imports of crude oil and refined petroleum products. Requirement for refinery feedstocks. – Bernard Leakey, Oil Branch	(613) 996-2221
Exports of natural gas. – Dennis Dubuc, Gas Branch	(613) 593-6432
Exports of liquefied petroleum gas. – Hans Pols, Gas Branch	(613) 593-7652

All written communications, including submissions, should be addressed to the Secretary of the Board at 473 Albert St., Ottawa, Ontario K1A 0E5.

Appendix 1 to Appendix A1-6

Format for the Presentation of Energy Demand Estimates

A. Total Final Demand, by Fuel for:

1. Refined Petroleum Products (by product)
2. Refinery Feedstocks, Domestic and Foreign
   (a) light crude oil and equivalent (including conventional light and medium crude oil, segregated pentanes plus, synthetic crude oil and exchange crude oil imports);
   (b) heavy crude oil (including Lloydminster Blend, Wainwright, Viking-Kinsella, Chauvin, Fosterton, Bow River, Smiley Coleville, Midale Wayburn and other streams less than 0.904 kg/m^3);
   (c) foreign crude oil
3. Natural Gas
4. Liquefied Petroleum Gases (ethane, propane, butanes)
5. Electricity (including own-use and losses)
6. Coal and Coke
7. Other Energy Forms (wood and wood products, pulping liquor, alcohol, biomass, solar, wind and tidal power).

B. By Sector for Secondary and Primary Energy Demand:

Secondary Energy Demand
a) residential;
b) commercial;
c) petrochemicals, including fuel and feedstock for basic petrochemicals, such as ammonia, methanol, ethylene and benzene and fuel for their primary derivatives;
d) other industrial uses, excluding thermal generation of electricity;
e) transportation, showing air, road, rail and marine separately;
f) other non-energy use (e.g. lubes, asphalt, etc.);
g) total secondary demand, which is the sum of sectors (a) through (f);

Primary Energy Demand
h) own use and losses, including transmission, processing and distribution losses, and including refinery fuels and pipeline fuel;
i) primary fuels used for generation of electricity, by utilities and by industry, where hydro and nuclear generation are converted at 10.5 megajoules per kwh;
j) primary fuels used for production of steam, where steam produced at nuclear plants is converted at 1.25 joules of energy input for every joule of steam produced, (80% conversion efficiency to steam on a fossil fuel equivalent basis); and
k) total primary energy, which is the sum of points (g), (h), (i) and (j), less total electricity demand (including own use and losses), less the total amount of steam demand plus natural gas reprocessing shrinkage, less demand for ethane.

C. Geographic Regions:

Atlantic (by province to the extent practicable)
Quebec
Ontario
Manitoba

Saskatchewan
Alberta
British Columbia, Yukon and N.W.T.
Total Canada

D. By fuel, sector and region, as indicated in the matrix format included in the list of available forms.

Appendix 2 to Appendix A1-6

Format for the Presentation of Energy Supply Estimates

1. Reserves and Productive Capacity of Canadian Oil

   (a) conventional crude oil in non-frontier areas from,
      (i) established reserves at 31 December 1982;
      (ii) reserves additions from appreciation and new discoveries, but excluding additions covered by (a) (iii) below;
      (iii) reserves additions from enhanced oil recovery from pools currently in the established reserves catagory, including future waterflood projects;
   (b) pentanes plus in non-frontier areas from established reserves and reserves additions;
   (c) non-conventional oil recoverable from,
      (i) oil sands mining;
      (ii) oil sands in situ operations;
   (d) crude oil and equivalent in frontier areas.

2. Reserves and Deliverability of Canadian Natural Gas

   (a) conventional natural gas in non-frontier areas from,
      (i) established marketable reserves at 31 December 1982;
      (ii) reserves additions from appreciation and from new discoveries;
   (b) frontier areas;
   (c) non-conventional sources.

3. Reserves and Production of Canadian Natural Gas Liquids

   (a) field plants processing gas from established oil and gas reservoirs;
   (b) reprocessing plants;
   (c) reserves additions;
   (d) synthetic crude oil plants;
   (e) refineries;
   (f) frontier areas.

4. Installed Capacity and Electricity Production by Fuel Type

Appendix 3 to Appendix A1-6

List of Available Forms

1. List of Pools and Pool Groupings for Crude Oil Reserves and Productive Capacity Data.
2. Crude Oil Reserves and Productive Capacity Data Sheet.
3. Gas Reserve Data Sheet.
4. Natural Gas Deliverability Data Sheet.
5. List of Gas Processing and Reprocessing Plants for NGL Supply Forecast.
6. Natural Gas Liquids Data Sheet.
7. Demand for Refinery Feedstocks and Breakdown of Refinery Demand for Refinery Feedstocks.
8. Electricity Requirements by Sector.
9. Forecast of Energy Generation by Major Fuel Type and Primary Equivalent.
10. Forecast of Installed Capacity by Major Fuel Type and Peak Load.
11. Pro Forma Matrix of Total Domestic Energy Demand by Sector and Energy Form.

Table A2-1
World Oil Prices
Comparison of Submittors' Views

($U.S. 1983 per Barrel)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
Amoco	29.5	29.5	29.5	29.5	29.5	29.5	29.5	29.5	29.5
APMC	29.5	27.6	26.3	26.3	26.3	26.3	—	—	—
Canadian-Montana	29.5	30.0	30.5	31.0	31.5	33.0	35.5	38.2	41.2
Chevron	29.0	—	28.0	—	—	30.0	33.0	40.0	—
CPA	29.5	27.9	26.3	26.6	—	29.2	31.8	—	—
GIC	29.5	27.6	26.3	26.3	26.3	26.3	27.6	29.1	30.5
GMi	29.5	27.6	27.6	27.6	—	27.9	28.1	28.4	28.8
Gulf	29.0	29.0	28.7	29.8	31.4	32.8	34.7	36.7	—
Husky/NOVA	29.5	27.3	25.7	25.7	25.7	25.7	27.6	29.6	31.8
Imperial	29.5	27.5	27.5	27.5	27.5	31.0	37.6	45.7	—
Petro-Canada	26.9	26.3	25.7	26.1	27.1	30.2	33.9	37.5	40.6
Petrosar	29.0	27.9	26.6	26.6	26.6	27.4	28.8	30.2	30.2
Suncor	29.0	29.4	29.8	30.3	30.7	32.0	34.4	—	—
TCPL	30.2	29.2	29.2	29.2	—	31.3	36.5	42.7	49.1
Texaco	29.5	27.6	26.0	26.0	26.0	26.3	27.6	—	—
TQM	29.5	27.6	28.1	28.7	—	31.0	34.1	37.5	41.3
Ultramar	29.5	27.6	26.3	26.3	26.3	26.3	—	—	—
WTCL	28.4	26.1	26.7	27.3	28.1	31.9	37.9	42.3	42.5
AECL	29.0	27.7	28.7	29.0	29.3	30.1	31.6	33.1	34.8
B.C. Hydro	29.1	26.8	26.8	26.8	26.8	27.2	28.6	30.0	—
EUPC	28.0	—	30.8	—	—	31.6	34.1	36.7	39.5
Hydro-Québec	29.5	27.6	27.4	27.1	27.1	27.1	27.1	27.1	—
Ontario Hydro	29.7	27.9	28.1	28.7	—	30.2	35.2	39.1	—
Tidal	29.5	—	—	27.0	—	30.0	—	50.0	—
Newfoundland	29.5	27.6	28.7	—	—	30.2	31.7	33.3	35.0
Nova Scotia	29.5	26.7	26.7	—	—	30.2	—	—	40.6
Quebec									
– Scenario 1	32.0	—	—	—	—	28.7	—	—	38.7
– Scenario 2	32.0	—	—	—	—	28.7	—	—	28.7
Ontario	29.5	27.6	27.6	27.6	27.6	32.1	37.4	40.9	45.0
Saskatchewan	29.5	29.9	30.4	30.8	31.3	33.1	36.5	40.3	44.5
Friends of the Earth	40.3	41.5	42.7	44.0	45.3	49.5	57.4	66.6	71.7
NEB – High	29.5	29.2	31.3	32.0	32.8	35.2	39.5	44.5	50.1
– Reference	29.5	27.6	26.3	26.3	26.3	27.9	30.9	34.1	37.6
– Low	29.5	26.3	25.0	25.2	25.3	25.8	26.5	27.3	28.1

Notes:

(1) Prices expressed in the submissions in constant U.S. dollars other than 1983 dollars were rebased to 1983 U.S. dollars using the U.S. GNP deflator. For the projection period 1984-2005, it was assumed that the U.S. GNP deflator would increase at 5.0 percent per year.

(2) When prices were only given in current U.S. dollars, they were converted to constant 1983 U.S. dollars by using the submittor's assumption on inflation, when available. When not available, it was assumed that the U.S. GNP deflator would rise, over the period 1984-2005, at an average annual rate of 5.0 percent.

Table A2-1 (Cont'd)

(3) Several submittors provided their profile for world oil prices in the form of average annual growth rates instead of in the form of levels. These growth rates were used to extrapolate the prices implied by the assumptions whenever we felt that they would reasonably represent the submittor's view. When a range of rates of growth was provided, the middle of the range was chosen. In the case of Shell's submission we felt that none of the above could be used without the risk of distorting the submittor's view. Shell's assumption is as follows:

> "The main assumption underlying the forecast is that world oil prices (Arab Marker, FOB Persian Gulf) will remain at about the current level for the next few years, before stabilizing, in constant dollar terms, during the latter half of the 1980s. In the 1990s, it is assumed that the real price will show a modest rate of escalation which will allow it to recover to 1982 levels by the end of this century".

Table A2-2
Real Gross National Product Growth Rates – Canada
Comparison of Submittors' Views

(Percent per Annum)

	1983-1990	1990-1995	1995-2000	2000-2005
Amoco	3.0-3.5[1]	—	—	—
APMC	3.1	2.0	2.0	2.0
CPA	3.0	3.0	—	—
Gulf	3.0	2.9	2.9	—
Husky/NOVA	3.6	3.0	3.0	3.0
Imperial	2.7	2.5	2.5	—
Petro-Canada[2]	3.8	3.4	3.4	—
Petrosar	3.3	3.3	3.3	3.3
Shell	1.6	4.5	4.0	—
Suncor	3.5	3.5	—	—
TCPL[2]	3.3	3.2	3.0	—
Texaco	2.9	2.6	—	—
Ultramar	2.3	—	—	—
AECL	3.5	3.3	3.2	2.2
B.C. Hydro	3.5	3.1	3.0	—
EUPC[2]	2.6	2.6	2.6	2.6
New Brunswick[2]	2.9	2.9	—	—
Saskatchewan	2.8	2.3	2.3	2.3
CP	2.7	—	—	—
Dofasco	2.0	3.0	3.0	—
Stelco	3.5	3.5	3.5	3.5
Friends of the Earth				
– Business as usual	4.3	4.3	4.3	—
– Consumer saturation	2.6	2.6	2.6	—
NEB – High	4.5	3.3	3.3	3.0
– Reference	3.4	3.3	3.1	2.5
– Low	2.0	3.0	3.0	2.5

(1) 1984-1988.
(2) Real Domestic Product rather than Gross National Product.

Table A2-3
Real Provincial Domestic Product Growth Rates – Canada and Regions
Comparison of Submittors' Views

(Percent per Annum)

	1983-1990	1990-1995	1995-2000	2000-2005
Atlantic Canada				
Petro-Canada	4.6	3.5	3.3	—
Gulf	2.8	2.8	2.8	—
NEB	3.4	3.4	3.3	2.7
Newfoundland				
Dept. of Mines & Energy	3.4	3.4	3.4	3.4
NEB	3.5	3.5	3.3	2.8
Prince Edward Island				
NEB	2.9	2.8	2.7	2.1
Nova Scotia				
Dept. of Mines & Energy	2.3	2.6	2.7	2.8
NEB	3.5	3.5	3.4	2.8
New Brunswick				
NBEPC	2.2	2.2	—	—
NEB	3.4	3.3	3.2	2.6
Central Canada				
Petro-Canada	3.2	2.6	3.2	—
TCPL	3.1	3.0	2.8	—
NEB	3.0	3.0	2.9	2.3
Quebec				
Petro-Canada	3.3	2.7	2.6	—
TCPL	3.0	2.9	2.7	—
Hydro-Québec	2.8	2.8	2.8	—
GIC	1.3	1.0	1.0	1.0
GMi	2.5	3.0	2.8	2.0
Ministry of Energy and Resources	2.9	2.9	2.9	3.0
Gulf	2.7	2.7	2.7	—
NEB	3.0	2.9	2.8	2.2
Ontario				
Petro-Canada	3.2	2.6	3.5	—
TCPL	3.2	3.1	2.9	—
Ontario Ministry of Energy	3.3	2.8	2.8	—
Ontario Hydro	2.5	2.5	2.5	—
Gulf	3.0	3.0	3.0	—
NEB	3.1	3.0	2.9	2.3

Table A2-3 (Cont'd)

	1983-1990	1990-1995	1995-2000	2000-2005
Prairies				
Petro-Canada	4.7	5.0	3.7	—
Gulf	3.2	3.2	3.2	—
NEB	3.5	3.6	3.4	2.9
Manitoba				
Petro-Canada	3.0	2.8	3.5	—
TCPL	2.7	2.6	2.4	—
NEB	2.5	2.4	2.2	1.6
Saskatchewan				
Petro-Canada	4.4	4.4	3.2	—
TCPL	3.4	3.4	3.1	—
NEB	3.4	3.4	3.3	2.7
Alberta				
Petro-Canada	5.2	5.7	3.9	—
EUPC	4.0	4.1	—	—
NEB	3.8	4.0	3.8	3.2
B.C. and Territories				
Petro-Canada	4.5	4.2	3.8	—
Gulf	3.2	3.2	3.2	—
Chevron	3.0-3.5	3.0-3.5	3.0-3.5	—
B.C. Hydro	4.2	4.2	4.2	—
NEB	3.8	3.7	3.6	3.0

Table A3-1
Historical Data – End Use Energy Demand by Sector – Canada

(Petajoules)

	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970
Residential	869	881	914	946	981	1001	1002	1035	1073	1116	1161
Commercial	261	288	293	340	368	417	468	512	576	631	667
Industrial	918	934	963	980	1073	1152	1207	1267	1334	1391	1459
Transportation	786	801	838	882	932	990	1054	1108	1165	1208	1275
Non-Energy	156	158	156	175	202	215	238	245	254	282	340
Total	**2291**	**3062**	**3165**	**3323**	**3556**	**3775**	**3969**	**4168**	**4402**	**4629**	**4901**

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
Residential	1176	1250	1212	1299	1288	1305	1262	1341	1353	1365	1297
Commercial	704	799	762	798	754	850	845	840	851	820	838
Industrial	1479	1561	1682	1761	1651	1980	2077	2143	2264	2284	2185
Transportation	1319	1413	1541	1601	1624	1691	1737	1799	1926	1962	1912
Non-Energy	347	369	414	414	411	461	545	571	648	625	607
Total	**5025**	**5391**	**5610**	**5873**	**5729**	**6287**	**6465**	**6696**	**7041**	**7057**	**6840**

Table A3-2
End Use Energy Demand by Sector – Canada and Regions
Comparison of Submittors' Views

(Petajoules)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
				Canada						
Residential										
Dome-High	1339	1241	1262	1237	1219	1202	1187	1219	1248	N/A
Dome-Low	1339	1241	1267	1257	1255	1254	1271	1342	1399	N/A
Gulf	1320	1236	1282	1292	1305	1327	1370	1446	1520	N/A
Husky/NOVA	1197	1125	1181	1198	1213	1237	1289	1367	1460	1571
Imperial	1238	1176	1181	1160	1149	1141	1163	1172	1184	N/A
Petro-Canada Base	1226	1201	1285	1316	1338	1359	1417	1534	1659	N/A
Petro-Canada High	1226	1200	1282	1293	1292	1297	1334	1435	1560	N/A
Petro-Canada Low	1226	1200	1282	1308	1333	1357	1438	1605	1789	N/A
Shell	1280	1279	1246	1242	1241	1242	1285	1300	1305	N/A
NEB	1349	1266	1256	1237	1228	1234	1262	1317	1381	1461
Commercial										
Dome-High	978	928	954	949	935	934	936	1004	1054	N/A
Dome-Low	978	928	958	966	972	981	1011	1115	1193	N/A
Gulf	868	872	891	908	920	912	951	1079	1267	N/A
Husky/NOVA	856	821	854	862	870	885	951	1120	1317	1528
Imperial	839	831	884	903	922	947	978	1069	1153	N/A
Petro-Canada Base	843	848	926	955	984	1013	1111	1286	1467	N/A
Petro-Canada High	843	847	923	933	943	959	1046	1209	1383	N/A
Petro-Canada Low	843	847	923	949	979	1011	1129	1350	1585	N/A
Shell	808	783	777	747	744	742	741	812	896	N/A
NEB	867	819	847	859	875	894	955	1074	1211	1363
Industrial										
Dome-High	1995	1974	2140	2251	2290	2349	2458	2751	3165	N/A
Dome-Low	1995	1974	2151	2304	2375	2458	2613	2967	3466	N/A
Gulf	1973	1970	2054	2104	2124	2130	2236	2491	2788	N/A
Husky/NOVA	2112	2078	2190	2273	2337	2406	2598	2935	3304	3687
Imperial	2065	2079	2223	2298	2346	2380	2515	2760	2969	N/A
Petro-Canada Base	1988	1887	1935	2036	2078	2119	2238	2490	2824	N/A
Petro-Canada High	1988	1886	1931	2008	2025	2039	2130	2353	2670	N/A
Petro-Canada Low	1988	1886	1931	2028	2072	2116	2261	2578	2981	N/A
Shell	1947	1982	2048	1984	2039	2096	2282	2737	3221	N/A
NEB	2001	2030	2096	2145	2191	2248	2422	2747	3118	3454

- Demand data provided by NEB for 1982 are published actuals except for wood, waste wood and pulping liquor, reprocessing fuel and pipeline transportation fuels.

  Wherever possible 1983 data were tracked to established trends published in the Statistics Canada monthly catalogues.

Table A3-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Canada (Cont'd)					
Transportation										
Dome-High	1655	1624	1671	1649	1613	1601	1579	1636	1673	N/A
Dome-Low	1655	1624	1678	1695	1718	1744	1815	2016	2155	N/A
Gulf	1747	1687	1718	1743	1765	1769	1818	1921	2026	N/A
Husky/NOVA	1794	1750	1774	1800	1805	1820	1884	2016	2179	2334
Imperial	1820	1751	1771	1769	1750	1743	1697	1578	1438	N/A
Petro-Canada-Base	1742	1688	1734	1755	1768	1762	1725	1722	1849	N/A
Petro-Canada-High	1742	1685	1726	1695	1657	1622	1565	1564	1695	N/A
Petro-Canada-Low	1742	1685	1726	1738	1768	1784	1834	1989	2261	N/A
Shell	1737	1650	1621	1587	1580	1564	1542	1591	1639	N/A
EMR	1709	1688	1754	1789	1822	1860	1977	2181	2398	N/A
Transport Canada	N/A	N/A	N/A	1820	N/A	N/A	2094	2174	2261	N/A
NEB	1739	1694	1683	1661	1633	1617	1613	1687	1796	1877
Non-Energy										
Dome-High	555	569	626	738	781	799	895	907	968	N/A
Dome-Low	555	569	626	738	781	799	895	907	968	N/A
Gulf	462	527	563	611	651	675	804	868	927	N/A
Imperial	524	586	617	665	687	694	707	770	811	N/A
Petro-Canada-Base	555	569	598	793	815	839	950	1080	1142	N/A
Shell	449	492	581	602	614	665	718	750	779	N/A
NEB	550	592	640	714	723	734	775	860	898	928
Total End Use										
CPA	6910	N/A	N/A	N/A	N/A	N/A	7782	8429	N/A	N/A
Dome-High	6523	6336	6654	6824	6839	6885	7056	7517	8109	N/A
Dome-Low	6523	6336	6681	6960	7100	7235	7604	8347	9181	N/A
Gulf	6370	6292	6508	6658	6766	6813	7180	7805	8528	N/A
Husky/NOVA	6317	6145	6391	6562	6661	6797	7240	8038	8962	9933
Imperial	6483	6424	6677	6795	6853	6905	7060	7350	7560	N/A
Petro-Canada-Base	6354	6194	6477	6854	6983	7092	7441	8111	8940	N/A
Shell	6222	6185	6273	6162	6219	6308	6568	7190	7839	N/A
NEB	6510	6407	6535	6639	6678	6759	7072	7752	8489	9168
					Atlantic					
Residential										
Gulf	113	101	101	101	101	102	105	108	110	N/A
Imperial	102	95	89	86	82	80	82	76	80	N/A
Petro-Canada-Base	84	89	99	107	112	117	129	146	162	N/A
Shell	91	86	85	84	83	83	98	99	97	N/A
NEB	114	104	104	102	101	102	105	114	123	131
Commercial										
Gulf	62	61	62	64	64	64	66	72	82	N/A
Imperial	51	46	47	47	48	49	52	60	65	N/A
Petro-Canada-Base	60	62	67	69	71	74	82	95	111	N/A
Shell	48	49	50	47	47	47	47	52	57	N/A
NEB	60	55	57	58	58	60	64	71	80	90

Table A3-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Atlantic (Cont'd)					
Industrial										
Gulf	143	138	144	148	149	150	159	179	201	N/A
Imperial	149	140	146	153	160	167	174	189	202	N/A
Petro-Canada-Base	152	123	123	123	127	128	141	167	211	N/A
Shell	145	146	150	142	145	149	160	187	220	N/A
NEB	153	144	148	150	152	155	167	194	223	252
Transportation										
Gulf	153	146	147	149	152	153	157	166	175	N/A
Imperial	163	164	167	166	163	163	157	134	123	N/A
Petro-Canada-Base	160	148	151	152	154	155	155	153	162	N/A
Shell	152	148	145	141	141	139	138	140	147	N/A
NEB	154	147	150	150	147	145	144	147	157	172
Non-Energy										
Gulf	12	11	12	13	14	15	15	15	16	N/A
Imperial	12	13	12	12	13	13	12	12	12	N/A
Petro-Canada-Base	12	13	14	16	17	18	20	24	28	N/A
Shell	12	9	10	11	11	12	13	15	16	N/A
NEB	12	13	14	14	14	15	15	17	18	20
Total End Use										
Gulf	482	458	466	474	480	483	501	540	583	N/A
Imperial	476	457	461	464	466	472	476	471	482	N/A
Petro-Canada-Base	467	435	454	466	481	492	527	585	674	N/A
Shell	448	438	440	425	428	430	455	492	537	N/A
NEB	493	463	472	474	473	477	497	545	605	667
					Newfoundland					
Total End Use										
Newfoundland	111	112	114	117	120	123	145	160	184	215
Shell	104	102	103	100	102	104	112	125	140	N/A
NEB	124	117	120	121	121	122	126	134	147	163
					Prince Edward Island					
Total End Use										
NEB	18	17	17	17	17	17	17	18	19	21
					Nova Scotia					
Total End Use										
Nova Scotia	180	178	178	183	185	187	185	193	203	215
NEB	190	178	182	182	182	182	190	209	232	257
					New Brunswick					
Total End Use										
New Brunswick	160	N/A	N/A	158	N/A	N/A	161	163	166	N/A
NEB	161	151	154	154	154	155	163	184	206	226

Table A3-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
				Quebec						
Residential										
GIC	N/A	N/A	267	258	250	N/A	259	261	263	265
Gulf	274	250	253	247	251	254	260	271	278	N/A
Imperial	280	266	258	248	244	242	250	251	253	N/A
Petro-Canada-Base	265	269	285	293	299	304	317	339	354	N/A
Shell	273	267	266	263	261	260	268	265	266	N/A
TCPL	260	275	279	282	285	288	297	305	307	312
Hydro-Québec(1)	293	N/A	N/A	N/A	273	N/A	276	280	284	N/A
Quebec-Case 1B(1)	297	N/A	N/A	N/A	N/A	N/A	N/A	269	270	274
NEB	306	290	286	285	285	287	295	307	326	345
Commercial										
GIC	N/A	N/A	185	179	174	N/A	178	183	193	204
Gulf	182	185	188	192	193	193	201	226	257	N/A
Imperial	163	169	175	179	180	183	187	201	214	N/A
Petro-Canada-Base	162	178	197	207	216	223	244	280	300	N/A
Shell	168	164	162	156	155	154	153	167	185	N/A
TCPL	170	166	173	178	179	182	183	198	212	231
Hydro-Québec(1)	165	N/A	N/A	N/A	162	N/A	176	191	212	N/A
Quebec-Case 1B(1)	162	N/A	N/A	N/A	N/A	N/A	N/A	183	192	204
NEB	167	159	163	166	169	172	185	206	230	255
Industrial										
GIC	N/A	N/A	452	472	492	N/A	511	549	601	657
Gulf	449	449	464	473	478	480	499	548	603	N/A
Imperial	469	450	481	493	498	504	514	565	596	N/A
Petro-Canada-Base	467	459	466	477	488	498	512	548	596	N/A
Shell	453	452	460	437	443	449	468	555	647	N/A
TCPL	410	437	448	470	477	482	497	526	538	556
Hydro-Québec(1)	515	N/A	N/A	N/A	514	N/A	563	640	713	N/A
Quebec-Case 1B(1)	460	N/A	N/A	N/A	N/A	N/A	N/A	707	759	839
NEB	467	469	478	484	490	502	540	609	691	767
Transportation										
GIC	N/A	N/A	354	369	385	N/A	389	396	401	406
Gulf	361	334	339	340	344	344	356	373	386	N/A
Imperial	369	343	335	330	324	320	304	299	272	N/A
Petro-Canada-Base	353	341	350	354	357	352	338	326	342	N/A
Shell	359	334	325	316	314	313	305	304	314	N/A
Hydro-Québec(1)	430	N/A	N/A	N/A	387	N/A	400	416	432	N/A
Quebec-Case 1B(1)	415	N/A	N/A	N/A	N/A	N/A	N/A	443	465	491
NEB	359	338	336	326	319	312	312	331	353	362
Non-Energy										
Gulf	88	91	95	98	100	102	104	108	111	N/A
Imperial	91	88	98	104	104	103	105	105	105	N/A
Petro-Canada-Base	89	90	93	95	99	101	113	193	201	N/A
Shell	86	85	87	86	88	90	96	103	107	N/A
NEB	89	84	81	82	84	85	88	94	100	106

Table A3-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Quebec (Cont'd)					
Total End Use										
CPA	1044	N/A	N/A	N/A	N/A	N/A	1095	1197	N/A	N/A
GIC	N/A	N/A	1343	1367	1392	N/A	1433	1491	1565	1645
GMi	1309	1300	1365	1378	1377	N/A	1390	1541	1699	1823
Gulf	1353	1310	1341	1350	1366	1370	1419	1525	1636	N/A
Imperial	1375	1318	1351	1358	1353	1356	1363	1424	1444	N/A
Petro-Canada-Base	1336	1337	1392	1426	1458	1478	1525	1685	1793	N/A
Shell	1339	1303	1298	1257	1260	1265	1289	1394	1519	N/A
Hydro-Québec[1]	1403	N/A	N/A	N/A	1336	N/A	1415	1527	1641	N/A
Quebec-Case 1B[1]	1334	N/A	N/A	N/A	N/A	N/A	N/A	1603	1686	1809
NEB	1388	1340	1345	1346	1351	1363	1427	1561	1715	1850
					Ontario					
Residential										
Gulf	452	429	443	449	453	457	468	485	503	N/A
Imperial	452	437	439	432	423	415	412	411	409	N/A
Petro-Canada-Base	443	441	461	472	479	486	502	533	571	N/A
Shell	446	437	434	432	432	432	439	440	436	N/A
TCPL	425	440	448	462	474	483	503	510	514	519
Ontario	453	465	470	474	472	471	466	461	453	N/A
NEB	475	455	450	441	437	438	447	463	480	506
Commercial										
Gulf	337	340	346	353	356	356	372	422	494	N/A
Imperial	316	316	343	348	354	362	371	402	431	N/A
Petro-Canada-Base	307	315	334	343	352	361	389	432	484	N/A
Shell	322	307	304	292	291	289	287	314	343	N/A
TCPL	316	308	315	323	322	322	326	360	394	434
Ontario	280	283	287	290	292	293	297	324	348	N/A
NEB	319	312	310	308	312	317	333	368	408	451
Industrial										
Gulf	675	690	727	747	752	751	784	867	970	N/A
Imperial	705	728	785	817	831	834	884	967	1023	N/A
Petro-Canada-Base	731	693	707	732	756	776	826	909	1008	N/A
Shell	693	701	722	691	707	725	780	954	1129	N/A
TCPL	647	702	740	766	795	817	865	918	960	1008
Ontario	768	815	834	851	900	913	1025	1110	1251	N/A
NEB	714	747	776	797	813	837	903	1029	1169	1290
Transportation										
Gulf	568	571	582	590	594	596	609	642	672	N/A
Imperial	577	573	582	584	577	569	540	460	423	N/A
Petro-Canada-Base	568	562	576	583	583	578	553	531	578	N/A
Shell	564	535	521	503	496	486	469	475	487	N/A
Ontario	554	570	565	557	555	557	567	604	635	N/A
NEB	564	566	555	555	543	541	539	565	591	585

[1] Hydro-Québec and the Quebec Government have presented their forecasts using the following years : 1981, 1986, 1991, 1996, 2001, 2006.

Table A3-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Ontario (Cont'd)					
Non-Energy										
Gulf	162	178	183	187	202	214	243	266	284	N/A
Imperial	176	202	199	167	164	168	169	173	182	N/A
Petro-Canada-Base	180	190	196	213	217	227	232	241	251	N/A
Shell	162	171	189	189	192	196	208	221	233	N/A
Ontario	153	158	160	160	165	168	182	195	210	N/A
NEB	170	178	193	211	211	206	210	217	224	231
Total End Use										
CPA	2365	N/A	N/A	N/A	N/A	N/A	2646	2867	N/A	N/A
Gulf	2194	2208	2282	2326	2358	2373	2476	2682	2923	N/A
Husky/NOVA	2174	2129	2202	2243	2267	2298	2385	2548	2746	2961
Imperial	2266	2297	2389	2420	2430	2429	2458	2494	2549	N/A
Petro-Canada-Base	2229	2201	2275	2342	2387	2429	2502	2646	2892	N/A
Shell	2187	2151	2171	2107	2118	2128	2183	2404	2628	N/A
Ontario	2208	2291	2316	2332	2384	2402	2537	2694	2897	N/A
NEB	2245	2261	2289	2323	2328	2352	2450	2665	2902	3092
					Manitoba					
Residential										
Gulf	53	50	51	52	52	53	54	56	58	N/A
Petro-Canada-Base	56	54	57	58	57	56	56	57	65	N/A
Shell	61	63	63	63	62	61	61	60	57	N/A
TCPL	48	49	50	52	51	52	53	54	55	55
NEB	59	55	55	54	54	54	55	54	53	53
Commercial										
Gulf	49	48	50	51	52	52	54	61	70	N/A
Petro-Canada-Base	45	41	43	42	42	41	43	49	57	N/A
Shell	36	36	36	34	34	34	33	37	40	N/A
TCPL	44	41	44	44	43	44	43	47	49	53
NEB	45	42	45	46	46	47	49	53	57	61
Industrial										
Gulf	47	47	47	48	49	49	52	58	64	N/A
Petro-Canada-Base	31	37	39	41	43	45	49	55	65	N/A
Shell	41	41	43	41	43	44	47	54	64	N/A
TCPL	42	40	42	41	43	44	45	49	50	53
NEB	35	39	42	45	47	48	53	58	63	67
Transportation										
Gulf	79	79	79	80	81	81	83	85	87	N/A
Petro-Canada-Base	78	79	82	81	78	76	70	68	74	N/A
Shell	79	69	67	66	66	65	65	66	69	N/A
NEB	79	80	77	75	74	73	75	80	90	100
Non-Energy										
Gulf	6	9	9	9	9	9	11	11	13	N/A
Petro-Canada-Base	9	9	9	10	10	10	11	11	12	N/A
Shell	11	7	7	7	7	8	8	9	10	N/A
NEB	10	10	10	10	10	10	11	11	12	12

Table A3-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Manitoba (Cont'd)					
Total End Use										
Gulf	234	232	237	241	243	244	254	271	292	N/A
Petro-Canada-Base	219	220	231	231	230	228	228	241	273	N/A
Shell	228	216	216	211	212	212	214	227	241	N/A
TCPL	136	133	137	138	140	140	144	151	155	162
NEB	229	226	229	230	232	234	244	259	278	297
					Saskatchewan					
Residential										
Gulf	71	67	71	72	72	74	77	83	90	N/A
Petro-Canada-Base	63	58	61	61	61	62	64	71	79	N/A
Shell	74	75	75	74	74	74	75	77	77	N/A
NEB	77	72	75	75	75	74	74	74	76	77
Commercial										
Gulf	40	40	42	42	42	41	44	50	60	N/A
Petro-Canada-Base	34	32	35	35	37	38	42	51	59	N/A
Shell	33	31	31	30	30	30	30	33	36	N/A
NEB	34	32	33	34	35	37	40	46	52	59
Industrial										
Gulf	61	62	63	64	65	65	69	77	86	N/A
Petro-Canada-Base	57	56	72	85	99	113	152	199	241	N/A
Shell	68	70	74	72	74	75	81	92	105	N/A
NEB	66	71	75	79	82	85	94	111	130	146
Transportation										
Gulf	92	93	94	95	96	96	97	99	102	N/A
Petro-Canada-Base	105	105	110	111	111	112	112	112	116	124
Shell	91	86	83	82	82	81	82	84	86	N/A
NEB	91	93	97	95	94	93	92	92	99	111
Non-Energy										
Gulf	14	13	13	14	14	15	15	15	15	N/A
Petro-Canada-Base	12	11	12	13	14	15	16	19	22	N/A
Shell	14	10	11	11	11	12	13	14	15	N/A
NEB	14	13	13	13	13	14	14	15	16	17
Total End Use										
Gulf	278	274	283	287	291	292	302	324	353	N/A
Husky/NOVA	275	265	276	283	285	291	310	346	390	437
Petro-Canada-Base	271	262	290	305	322	339	387	456	524	N/A
Shell	280	272	273	269	271	271	280	299	320	N/A
NEB	282	281	294	297	300	304	316	342	377	414

Table A3-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Alberta					
Residential										
Gulf	178	168	180	184	188	190	200	218	238	N/A
Imperial	175	160	170	171	174	177	192	203	207	N/A
Petro-Canada-Base	174	151	163	162	162	163	168	187	208	N/A
Shell	208	190	193	195	196	198	205	216	223	N/A
NEB	192	172	167	161	158	159	166	176	188	205
Commercial										
Gulf	157	156	162	167	170	170	178	208	251	N/A
Imperial	140	146	157	161	164	167	180	199	219	N/A
Petro-Canada-Base	144	132	151	156	163	170	194	242	291	N/A
Shell	118	113	112	108	108	108	110	123	138	N/A
NEB	144	129	143	148	153	158	174	203	236	276
Industrial										
Gulf	242	227	235	241	246	248	263	303	353	N/A
Imperial	266	298	322	327	335	340	360	397	436	N/A
Petro-Canada-Base	205	188	202	203	210	216	234	274	317	N/A
Shell	250	272	316	344	364	424	512	597	689	N/A
NEB	175	165	169	172	176	181	199	236	279	320
Transportation										
Gulf	251	240	247	252	257	259	267	294	327	N/A
Imperial	272	267	273	276	281	284	285	280	253	N/A
Petro-Canada-Base	266	256	265	269	274	277	286	312	342	N/A
Shell	250	241	244	246	248	248	253	282	289	N/A
NEB	251	250	248	240	237	233	227	233	254	272
Non-Energy										
Gulf	163	201	217	255	274	283	376	396	429	N/A
Imperial	158	186	209	252	265	267	267	328	359	N/A
Petro-Canada-Base	221	220	234	402	405	408	493	521	548	N/A
Shell	122	148	192	193	196	199	209	216	224	N/A
NEB	224	260	295	347	353	357	376	443	463	474
Total End Use										
Gulf	990	992	1041	1098	1133	1150	1284	1417	1598	N/A
Husky/NOVA	990	973	1022	1070	1096	1134	1263	1458	1680	1903
Imperial	1011	1057	1132	1187	1219	1237	1203	1407	1474	N/A
Petro-Canada	1009	948	1015	1192	1213	1234	1374	1537	1708	N/A
Shell	948	964	1056	1085	1113	1179	1290	1434	1564	N/A
NEB	986	976	1022	1069	1077	1089	1141	1291	1419	1546
				British Columbia and Territories						
Residential										
Gulf	120	113	119	121	125	127	132	140	147	N/A
Imperial	112	109	113	111	112	113	114	117	119	N/A
Petro-Canada-Base	110	106	120	124	126	128	134	149	167	N/A
Shell	128	128	131	132	133	134	139	144	149	N/A
NEB	126	117	119	119	119	119	121	128	136	144

Table A3-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
				British Columbia and Territories (Cont'd)						
Commercial										
Gulf	100	100	103	106	106	106	111	126	149	N/A
Imperial	85	83	87	90	94	99	102	111	121	N/A
Petro-Canada-Base	91	88	99	101	102	104	113	133	159	N/A
Shell	84	83	83	79	79	79	79	87	96	N/A
NEB	99	90	97	99	101	103	110	127	147	171
Industrial										
Gulf	356	357	373	383	387	388	411	459	512	N/A
Imperial	370	347	370	384	398	410	448	496	554	N/A
Petro-Canada-Base	346	331	324	374	354	340	321	333	381	N/A
Shell	320	327	338	328	335	341	360	423	492	N/A
NEB	390	396	410	417	430	438	466	510	563	614
Transportation										
Gulf	243	224	229	237	241	240	249	262	277	N/A
Imperial	241	224	228	228	227	230	234	226	205	N/A
Petro-Canada-Base	245	231	237	242	244	245	243	251	262	N/A
Shell	239	237	236	234	234	233	231	239	246	N/A
NEB	243	222	225	229	229	231	239	260	281	304
Non-Energy										
Gulf	18	24	34	35	37	37	40	58	59	N/A
Imperial	21	37	35	35	36	36	51	50	52	N/A
Petro-Canada-Base	31	35	39	45	53	61	65	72	79	N/A
NEB	31	34	35	36	38	48	61	64	66	69
Total End Use										
CPA	863	N/A	N/A	N/A	N/A	N/A	1016	1101	N/A	N/A
Gulf	838	818	859	882	895	898	943	1044	1144	N/A
Husky/NOVA	810	788	833	865	888	918	1007	1167	1345	1525
Imperial	830	800	832	849	867	888	947	1000	1050	N/A
Petro-Canada-Base	823	791	820	886	880	877	876	938	1048	N/A
Shell	791	806	819	806	815	823	855	941	1031	N/A
NEB	888	859	885	899	916	940	997	1089	1193	1302

Table A4-1
Historical Data – End Use Energy Demand by Fuel – Canada

(Petajoules)

	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970
Electricity	N/A	N/A	379.0	397.3	436.8	470.9	512.6	542.6	579.4	624.2	664.0
Oil Products	N/A	N/A	1801.7	1917.7	2057.4	2202.9	2316.8	2466.7	2612.3	2739.8	2923.0
Natural Gas	N/A	N/A	411.2	444.0	499.1	545.5	600.5	652.6	719.0	816.1	879.2
NGL	N/A	N/A	21.2	25.3	29.4	37.0	46.7	47.3	46.4	55.4	53.5
Coal, Coke & Coke Oven Gas	N/A	N/A	440.3	436.3	439.1	429.8	410.2	377.2	366.9	320.7	313.0
Renewables & Steam	N/A	N/A	111.5	102.6	94.6	88.8	82.6	81.5	78.1	72.5	68.7
Total	**N/A**	**N/A**	**3164.8**	**3323.2**	**3556.4**	**3775.0**	**3969.3**	**4167.9**	**4402.1**	**4628.8**	**4901.4**

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
Electricity	698.6	758.2	816.5	872.0	856.9	918.3	986.7	1032.7	1059.3	1100.7	1139.2
Oil Products	2968.3	3165.7	3295.3	3384.2	3289.7	3391.4	3416.7	3475.8	3618.5	3555.4	3336.5
Natural Gas	974.7	1092.9	1112.3	1222.7	1208.0	1326.5	1416.6	1495.8	1554.2	1557.1	1535.6
NGL	63.2	67.7	66.4	82.1	77.3	88.8	89.6	64.6	94.9	105.1	111.9
Coal, Coke & Coke Oven Gas	257.4	250.0	262.5	253.3	234.3	242.2	236.6	246.6	255.2	252.8	227.1
Renewables & Steam	62.6	56.6	57.3	58.4	62.6	319.7	319.1	380.0	458.8	485.5	489.3
Total	**5024.8**	**5391.2**	**5610.2**	**5872.8**	**5728.8**	**6286.8**	**6465.5**	**6695.5**	**7041.1**	**7056.7**	**6839.7**

Table A4-2
End Use Energy Demand by Fuel – Canada and Regions
Comparison of Submittors' Views

(Petajoules)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
				Canada						
Electricity										
Gulf	1129	1165	1248	1303	1339	1365	1483	1710	1955	N/A
Husky/NOVA	1131	1136	1168	1179	1192	1220	1300	1487	1718	1969
Imperial	1131	1185	1235	1284	1331	1377	1489	1680	1811	N/A
Petro-Canada – Base	1125	1158	1237	1308	1361	1418	1612	1994	2426	N/A
Petro-Canada – High	1125	1158	1238	1312	1372	1431	1632	1991	2398	N/A
Petro-Canada – Low	1125	1158	1238	1311	1366	1424	1612	1999	2411	N/A
Shell	1143	1153	1173	1155	1172	1190	1245	1386	1547	N/A
NEB	1129	1161	1222	1272	1310	1353	1486	1720	1977	2211
Oil Products										
CPA	3312	N/A	N/A	N/A	N/A	N/A	3279	3322	N/A	N/A
Dome – High	3121	2980	3022	2994	2910	2882	2825	2868	2966	N/A
Dome – Low	3121	2980	3036	3078	3093	3121	3205	3472	3711	N/A
Gulf	2975	2784	2778	2785	2799	2788	2836	2924	3040	N/A
Husky/NOVA	3045	2883	2961	3014	3023	3047	3162	3364	3647	3941
Imperial	3023	2851	2816	2751	2700	2677	2582	2363	2207	N/A
Petro-Canada – Base	2947	2788	2854	2894	2894	2876	2786	2752	2835	N/A
Petro-Canada – High	2947	2783	2843	2810	2735	2669	2547	2517	2622	N/A
Petro-Canada – Low	2947	2783	2843	2869	2888	2895	2912	3076	3331	N/A
Shell	2953	2811	2772	2686	2673	2651	2625	2676	2744	N/A
Texaco	3397	3134	3117	3080	3045	3020	2995	3099	N/A	N/A
NEB	2965	2773	2718	2660	2584	2531	2482	2509	2630	2750
Natural Gas										
Amoco	N/A	1530	1580	1630	1680	1750	1950	2210	2530	2950
CPA	1707	N/A	N/A	N/A	N/A	N/A	2096	2363	N/A	N/A
Dome – High	1582	1516	1607	1705	1730	1747	1840	2020	2205	N/A
Dome – Low	1582	1516	1640	1732	1788	1833	2001	2281	2577	N/A
Gulf	1584	1619	1704	1758	1795	1821	1928	2100	2302	N/A
Husky/NOVA	1584	1568	1639	1701	1755	1819	1980	2289	2588	2880
Imperial	1627	1690	1880	1934	1975	1986	2059	2219	2296	N/A
Petro-Canada – Base	1586	1558	1730	1941	2024	2097	2296	2565	2808	N/A
Petro-Canada – High	1586	1557	1725	1895	1935	1972	2118	2340	2558	N/A
Petro-Canada – Low	1586	1557	1725	1926	2012	2090	2335	2677	3069	N/A
Shell	1551	1595	1692	1685	1725	1767	1908	2189	2446	N/A
NEB	1585	1573	1651	1725	1774	1833	2012	2313	2591	2857

• Demand data provided by NEB for 1982 are published actuals except for wood, waste wood and pulping liquor, reprocessing fuel and pipeline transportation fuels. Wherever possible 1983 data were tracked to established trends published in the Statistics Canada monthly catalogues.

Table A4-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
				Canada (cont'd)						
Ethane										
Amoco	22	34	37	53	69	85	101	133	133	133
Gulf	31	37	55	71	82	84	123	129	136	N/A
Husky/NOVA	21	33	48	70	76	79	115	126	126	126
Imperial	24	28	39	60	71	73	73	110	135	N/A
Shell	22	27	51	70	70	109	122	122	122	N/A
NEB	22	35	49	73	75	75	75	108	115	115
LPG										
Dome – Low	N/A	111	131	136	142	142	143	143	140	140
Gulf	78	90	101	106	106	106	110	118	127	N/A
Imperial	87	93	97	129	122	122	143	142	142	N/A
Petro-Canada – Base	112	123	144	197	201	204	252	287	296	N/A
Shell	63	66	67	67	67	69	70	75	78	N/A
NEB	80	90	99	102	117	132	140	153	160	173
Coal, Coke and Coke Oven Gas										
CPA	204	N/A	N/A	N/A	N/A	N/A	283	367	N/A	N/A
Gulf	222	220	233	239	239	238	253	278	317	N/A
Husky/NOVA	211	210	234	239	241	243	251	247	238	227
Imperial	224	214	226	239	247	254	265	323	344	N/A
Petro-Canada – Base	210	195	194	197	199	205	214	233	248	N/A
Petro-Canada – High	210	195	194	196	198	203	212	232	248	N/A
Petro-Canada – Low	210	195	194	197	200	205	215	238	263	N/A
Shell	213	216	223	213	220	228	254	335	420	N/A
NEB	205	233	251	257	257	264	277	311	349	376
Waste Wood and Pulping Liquor										
CPA	315	N/A	N/A	N/A	N/A	N/A	438	494	N/A	N/A
Dome – Low	315	310	319	324	328	335	365	420	500	N/A
Gulf	281	303	320	329	336	340	375	434	487	N/A
Husky/NOVA	324	315	339	358	372	388	431	509	599	701
Imperial	324	318	333	347	357	368	402	458	522	N/A
Petro-Canada – Base	315	319	263	259	238	222	194	171	176	N/A
Petro-Canada – High	315	318	262	255	232	214	186	169	180	N/A
Petro-Canada – Low	315	318	262	257	236	221	197	192	201	N/A
Shell	278	285	297	287	291	295	307	358	409	N/A
NEB	365	384	401	409	415	421	438	442	445	445
Solar and Wood										
Gulf	69	69	68	68	69	69	72	110	163	N/A
Husky/NOVA	0	2	2	1	1	2	3	16	46	90
Imperial	40	42	43	43	41	39	38	45	96	N/A
Petro-Canada – Base	5	5	7	11	16	20	34	59	94	N/A
Petro-Canada – High	5	5	7	11	15	19	32	57	92	N/A
Petro-Canada – Low	5	5	7	11	15	20	34	64	105	N/A
Shell	0	0	0	0	0	0	38	52	75	N/A
NEB	97	100	103	106	113	118	136	171	197	219

Table A4-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
				Canada (Cont'd)						
Total End Use										
CPA	6910	N/A	N/A	N/A	N/A	N/A	7782	8429	N/A	N/A
Dome – Low	6523	6336	6681	6960	7100	7235	7604	8347	9181	N/A
Gulf	6370	6292	6508	6658	6766	6813	7180	7805	8528	N/A
Husky/NOVA	6317	6145	6391	6562	6661	6797	7240	8038	8962	9933
Imperial	6483	6424	6677	6795	6853	6905	7060	7350	7560	N/A
Petro-Canada – Base	6354	6194	6477	6854	6983	7092	7441	8111	8940	N/A
Shell	6222	6185	6273	6162	6219	6308	6568	7190	7839	N/A
NEB	6510	6407	6535	6639	6678	6759	7072	7752	8489	9168
				Atlantic						
Electricity										
Gulf	78	79	87	95	101	106	120	136	154	NA
Imperial	78	83	87	90	94	97	106	119	130	NA
Petro-Canada – Base	78	82	88	91	96	100	125	173	233	NA
Shell	81	84	86	85	87	89	95	107	121	NA
NEB	78	80	87	91	95	100	111	136	167	191
Oil Products										
Gulf	335	309	307	305	304	302	288	278	281	NA
Imperial	335	305	300	294	289	288	281	207	189	NA
Petro-Canada – Base	326	294	305	311	317	320	323	312	321	NA
Shell	315	300	298	289	287	285	283	280	285	NA
NEB	327	294	295	290	285	282	277	261	261	281
Natural Gas										
Gulf	0	1	1	1	1	1	12	33	40	N/A
Imperial	0	0	0	0	0	0	0	51	60	N/A
Petro-Canada – Base	0	0	0	0	0	0	2	40	66	N/A
Shell	0	0	0	0	2	4	11	32	50	N/A
NEB	0	0	0	0	0	0	11	41	62	77
LPG										
Gulf	4	4	4	4	4	4	4	5	6	N/A
Imperial	4	4	3	3	3	3	4	4	4	N/A
Petro-Canada – Base	6	6	6	7	7	7	7	4	4	N/A
Shell	4	4	4	4	4	4	4	4	5	N/A
NEB	4	4	4	4	4	4	5	7	8	8
Coal, Coke and Coke Oven Gas										
Gulf	18	18	19	20	21	21	24	27	31	N/A
Imperial	13	16	21	24	27	30	28	30	34	N/A
Petro-Canada – Base	10	10	10	11	11	12	13	12	12	N/A
Shell	19	19	19	17	17	17	17	17	16	N/A
NEB	10	11	12	13	13	14	14	17	19	21

Table A4-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Atlantic (Cont'd)					
Waste Wood and Pulping Liquor										
Gulf	23	24	25	26	27	27	30	36	44	N/A
Imperial	31	33	34	36	37	38	42	48	56	N/A
Petro-Canada – Base	33	32	30	31	33	34	37	26	22	N/A
Shell	31	31	32	30	31	31	32	37	42	N/A
NEB	31	34	35	36	37	37	38	39	39	39
Solar and Wood										
Gulf	24	24	24	23	23	23	23	25	28	N/A
Imperial	46	49	51	53	53	54	58	59	66	N/A
Petro-Canada – Base	33	32	31	33	35	37	41	31	27	N/A
Shell	31	31	32	30	31	31	46	53	60	N/A
NEB	24	25	26	26	27	28	31	38	42	45
Total End Use										
Gulf	482	458	466	474	480	483	501	540	583	N/A
Imperial	476	457	461	464	466	472	476	471	482	N/A
Petro-Canada – Base	467	435	454	466	481	492	527	585	674	N/A
Shell	448	438	440	425	428	430	455	492	537	N/A
NEB	493	463	472	474	473	477	497	545	605	667
					Newfoundland					
Electricity										
Newfoundland	27	27	29	31	31	32	46	51	59	67
Shell	27	29	29	29	29	30	32	38	44	N/A
NEB	27	28	31	32	34	35	39	48	59	67
Oil Products										
Newfoundland	82	82	82	84	86	89	96	107	124	145
Shell	77	73	73	72	72	73	77	84	92	N/A
NEB	81	73	74	72	71	71	70	66	67	73
Total End Use										
Newfoundland	111	112	114	117	120	123	145	160	184	215
Shell	104	102	103	100	102	104	112	125	140	N/A
NEB	124	117	120	121	121	122	126	134	147	163
					Prince Edward Island					
Electricity										
Maritime Electric	2	2	2	2	2	2	2	2	2	3
NEB	2	2	2	2	2	2	2	3	3	4
Oil Products										
NEB	14	13	13	12	12	12	12	12	12	13
Total End Use										
NEB	18	17	17	17	17	17	18	19	19	21

Table A4-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Nova Scotia										
Electricity										
Nova Scotia	22	22	22	24	24	25	26	30	33	37
NEB	21	22	24	25	26	27	31	37	46	53
Oil Products										
Nova Scotia	125	123	124	128	128	129	125	130	135	142
NEB	129	116	117	115	113	112	111	106	106	115
Natural Gas										
NEB	0	0	0	0	0	0	5	19	30	38
Total End Use										
Nova Scotia	180	178	178	183	185	187	185	193	203	215
NEB	190	179	182	182	182	182	190	209	232	257
New Brunswick										
Electricity										
New Brunswick	27	N/A	N/A	34	N/A	N/A	38	42	46	N/A
NBEPC	26	29	31	32	33	35	37	42	N/A	N/A
NEB	27	28	31	32	34	35	39	48	59	68
Oil Products										
New Brunswick	109	N/A	N/A	93	N/A	N/A	86	66	60	N/A
NEB	103	92	92	90	88	87	84	78	76	80
Natural Gas										
New Brunswick	1	N/A	N/A	1	N/A	N/A	4	23	26	N/A
NEB	1	1	1	1	1	1	6	22	32	38
Total End Use										
New Brunswick	160	N/A	N/A	158	N/A	N/A	161	163	166	N/A
NEB	161	151	154	154	154	155	163	184	206	226
Quebec										
Electricity										
GIC	N/A	N/A	430	450	470	N/A	500	542	607	655
Gulf	390	413	447	465	473	481	518	585	651	N/A
Imperial	389	406	417	426	434	442	470	508	529	N/A
Petro-Canada – Base	389	393	401	404	407	414	442	517	588	N/A
Shell	389	393	399	389	394	399	416	461	516	N/A
TCPL	380	436	465	482	496	508	542	585	627	671
Hydro-Québec[1]	397	N/A	N/A	N/A	470	N/A	507	551	621	N/A
Quebec-Case 1B[1]	398	N/A	N/A	N/A	N/A	N/A	N/A	717	796	879
NEB	390	400	427	447	460	476	526	608	694	771

Table A4-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
				Quebec (Cont'd)						
Oil Products										
CPA	859	N/A	N/A	N/A	N/A	N/A	766	778	N/A	N/A
GIC	N/A	N/A	661	638	620	N/A	596	598	600	624
Gulf	766	688	664	641	643	636	631	631	629	N/A
Imperial	773	685	659	641	623	609	568	532	489	N/A
Petro-Canada – Base	753	713	728	727	723	707	659	633	600	N/A
Shell	758	708	674	643	634	627	604	596	601	N/A
TCPL	335	299	277	264	247	236	203	193	166	143
Hydro-Québec(1)	797	N/A	N/A	N/A	620	N/A	591	602	603	N/A
Quebec-Case 1B(1)	800	N/A	N/A	N/A	N/A	N/A	N/A	595	572	563
NEB	767	679	638	601	582	566	543	538	555	573
Natural Gas										
CPA	111	N/A	N/A	N/A	N/A	N/A	219	299	N/A	N/A
GIC	N/A	N/A	149	174	194	N/A	223	231	233	235
GMi	112	138	151	176	191	N/A	227	267	309	343
Gulf	111	114	128	138	142	145	149	165	185	N/A
Imperial	111	128	174	190	197	205	219	267	283	N/A
Petro-Canada – Base	110	139	178	211	242	271	338	413	465	N/A
Shell	110	119	140	142	147	152	169	212	246	N/A
TCPL	111	128	141	166	183	192	211	222	228	234
Hydro-Québec(1)	116	N/A	N/A	N/A	136	N/A	198	246	281	N/A
Quebec-Case 1B(1)	119	N/A	N/A	N/A	N/A	N/A	N/A	234	234	244
NEB	111	134	143	158	166	175	204	242	281	312
LPG										
Gulf	17	17	18	18	18	18	19	22	24	N/A
Imperial	17	13	13	9	9	9	11	10	9	N/A
Petro-Canada – Base	14	15	15	15	15	15	15	43	45	N/A
Shell	13	13	13	13	13	13	14	14	15	N/A
NEB	16	16	24	26	26	27	29	32	34	37
Coal, Coke and Coke Oven Gas										
CPA	17	N/A	N/A	N/A	N/A	N/A	27	30	N/A	N/A
GIC	N/A	N/A	17	17	17	N/A	17	17	17	17
Gulf	14	14	15	15	15	15	17	19	21	N/A
Imperial	17	22	22	22	22	22	24	27	31	N/A
Petro-Canada – Base	17	17	16	16	15	15	13	12	11	N/A
Shell	16	16	16	17	18	18	21	32	44	N/A
TCPL	17	17	17	19	22	25	31	38	43	50
Hydro-Québec(1)	17	N/A	N/A	N/A	20	N/A	22	25	27	N/A
Quebec-Case 1B(1)	17	N/A	N/A	N/A	N/A	N/A	N/A	24	30	33
NEB	17	18	17	17	17	17	17	20	22	25
Waste Wood and Pulping Liquor										
Gulf	42	49	55	59	61	63	70	81	94	N/A
Imperial	57	52	54	56	57	58	61	70	82	N/A
Petro-Canada – Base	52	58	52	50	50	49	47	47	51	N/A
Shell	54	54	56	53	54	55	56	68	81	N/A
TCPL	20	21	21	22	22	23	25	28	31	34
Hydro-Québec(1)	55	N/A	N/A	N/A	65	N/A	70	75	80	N/A
NEB	57	61	63	64	65	66	68	68	69	69

Table A4-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
				Quebec (Cont'd)						
Solar and Wood										
Gulf	14	14	14	14	14	14	14	15	20	N/A
Imperial	10	10	11	11	10	9	8	6	14	N/A
Petro-Canada – Base	1	2	2	3	4	4	6	9	N/A	N/A
Shell	0	0	0	0	0	0	8	9	10	N/A
Hydro-Québec[1]	21	N/A	N/A	N/A	26	N/A	28	28	29	N/A
NEB	31	32	33	34	34	35	36	44	45	45
Total End Use										
CPA	1044	N/A	N/A	N/A	N/A	N/A	1095	1197	N/A	N/A
GIC	N/A	N/A	1343	1367	1392	N/A	1433	1491	1565	1645
GMi	1309	1300	1365	1378	1377	N/A	1390	1541	1699	1823
Gulf	1353	1310	1341	1350	1366	1370	1419	1525	1636	N/A
Imperial	1375	1318	1351	1358	1353	1356	1363	1424	1444	N/A
Petro-Canada – Base	1336	1337	1392	1426	1458	1478	1525	1685	1793	N/A
Shell	1339	1303	1298	1257	1260	1265	1289	1394	1519	N/A
Hydro-Québec[1]	1403	N/A	N/A	N/A	1336	N/A	1415	1527	1641	N/A
Quebec-Case 1B[1]	1334	N/A	N/A	N/A	N/A	N/A	N/A	1603	1686	1809
NEB	1388	1340	1345	1346	1351	1363	1427	1561	1715	1850
				Ontario						
Electricity										
CPA	421	N/A	N/A	N/A	N/A	N/A	517	579	N/A	N/A
Gulf	354	370	392	410	425	432	470	532	642	N/A
Husky/NOVA	355	360	373	375	376	380	396	437	497	560
Imperial	354	378	395	412	430	447	481	545	588	N/A
Petro-Canada – Base	355	370	400	427	451	474	539	652	777	N/A
Shell	370	369	375	371	377	381	395	442	485	N/A
TCPL	353	371	388	400	412	423	452	482	513	546
Ontario Hydro	369	375	391	407	416	423	448	498	542	592
Ontario	346	358	368	377	383	390	416	469	532	N/A
NEB	355	369	383	397	407	419	457	518	582	642
Oil Products										
CPA	1030	N/A	N/A	N/A	N/A	N/A	1028	1044	N/A	N/A
Gulf	923	891	895	893	892	887	906	933	965	N/A
Husky/NOVA	936	902	918	927	925	927	933	955	997	1043
Imperial	961	964	953	903	881	869	821	723	681	N/A
Petro-Canada – Base	925	898	914	926	923	922	883	837	869	N/A
Shell	935	892	880	847	837	826	807	800	806	N/A
Ontario	941	968	960	942	942	932	924	940	969	N/A
NEB	918	892	878	870	831	800	780	797	832	837

[1] Hydro-Québec and the Quebec Government have presented their forecasts using the following years: 1981, 1986, 1991, 1996, 2001, 2006.

Table A4-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Ontario (Cont'd)					
Natural Gas										
CPA	692	N/A	N/A	N/A	N/A	N/A	808	883	N/A	N/A
Gulf	658	671	701	720	738	753	786	843	906	N/A
Husky/NOVA	658	642	658	682	704	724	778	871	963	1056
Imperial	671	691	761	779	795	789	807	814	830	N/A
Petro-Canada – Base	655	648	685	711	730	744	778	819	868	N/A
Shell	653	656	672	658	666	675	701	805	899	N/A
TCPL	656	679	696	705	712	719	737	797	854	915
Ontario	637	667	690	707	733	743	822	854	912	N/A
NEB	658	650	673	700	719	740	802	895	991	1084
LPG										
Gulf	31	38	41	44	44	44	45	46	48	N/A
Imperial	29	37	39	76	71	70	75	74	74	N/A
Petro-Canada – Base	21	34	37	39	43	46	53	61	69	N/A
Shell	15	14	15	14	14	14	15	16	16	N/A
NEB	23	35	36	37	50	63	64	67	67	69
Coal, Coke and Coke Oven Gas										
CPA	164	N/A	N/A	N/A	N/A	N/A	220	281	N/A	N/A
Gulf	177	173	184	188	188	186	195	214	244	N/A
Husky/NOVA	166	170	194	198	200	202	209	203	190	177
Imperial	181	164	171	179	180	182	195	247	261	N/A
Petro-Canada – Base	174	158	158	160	163	168	179	200	216	N/A
Shell	161	166	173	164	170	177	198	263	327	N/A
TCPL	128	162	185	207	234	257	305	334	350	367
Ontario	177	189	201	207	222	230	250	277	310	N/A
NEB	165	188	205	211	212	218	231	261	292	314
Waste Wood and Pulping Liquor										
CPA	58	N/A	N/A	N/A	N/A	N/A	73	80	N/A	N/A
Gulf	43	47	51	52	52	52	55	60	64	N/A
Husky/NOVA	59	55	58	61	63	65	69	81	99	125
Imperial	59	53	55	57	58	60	64	72	81	N/A
Petro-Canada – Base	62	61	51	49	47	45	42	41	44	N/A
TCPL	20	21	21	21	21	21	21	22	23	23
Ontario	59	59	60	60	61	62	66	69	78	N/A
NEB	59	60	61	61	62	62	63	64	64	64
Solar and Wood										
Gulf	19	19	19	19	19	20	21	35	54	N/A
Imperial	9	9	9	9	9	8	9	12	28	N/A
Petro-Canada – Base	1	0	0	1	1	2	5	12	22	N/A
Shell	53	54	56	53	54	55	67	78	95	N/A
Ontario	11	11	12	13	13	14	14	19	22	N/A
NEB	24	25	25	26	28	30	37	48	57	66

Table A4-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
				Ontario (Cont'd)						
Total End Use										
CPA	2365	N/A	N/A	N/A	N/A	N/A	2646	2867	N/A	N/A
Gulf	2194	2208	2282	2326	2358	2373	2476	2682	2923	N/A
Husky/NOVA	2174	2129	2202	2243	2267	2298	2385	2548	2746	2961
Imperial	2266	2297	2389	2420	2430	2429	2458	2494	2549	N/A
Petro-Canada – Base	2229	2201	2275	2342	2387	2429	2502	2646	2892	N/A
Shell	2187	2151	2171	2107	2118	2128	2183	2404	2628	N/A
Ontario	2208	2291	2316	2332	2384	2402	2537	2694	2897	N/A
NEB	2245	2261	2289	2323	2328	2352	2450	2665	2902	3092
				Manitoba						
Electricity										
Gulf	42	42	44	45	47	48	53	59	65	N/A
Petro-Canada – Base	41	43	46	48	50	53	59	72	91	N/A
Shell	43	44	45	44	44	44	46	48	51	N/A
TCPL	43	46	49	49	53	54	58	63	68	74
Manitoba Hydro	42	44	46	47	49	50	55	64	72	78
NEB	42	42	44	46	47	48	51	56	60	63
Oil Products										
Gulf	107	102	103	103	103	103	106	109	111	N/A
Petro-Canada – Base	105	104	108	106	103	99	93	92	99	N/A
Shell	105	93	90	89	89	88	88	91	96	N/A
TCPL	18	14	12	11	10	9	9	8	6	5
NEB	107	105	101	98	96	95	96	99	109	119
Natural Gas										
Gulf	67	70	71	73	73	73	75	79	87	N/A
Petro-Canada – Base	65	63	67	67	67	66	65	64	67	N/A
Shell	67	66	67	65	65	66	66	71	75	N/A
TCPL	69	68	71	73	72	72	72	75	76	78
NEB	67	64	67	70	71	72	76	82	87	91
Propane										
Gulf	4	4	4	4	4	4	4	5	5	N/A
Petro-Canada – Base	4	4	4	4	4	3	3	3	3	N/A
Shell	5	5	5	5	5	5	5	5	5	N/A
NEB	4	4	3	3	3	3	4	4	4	5
Coal, Coke and Coke Oven Gas										
Gulf	3	3	3	3	3	3	4	4	5	N/A
Petro-Canada – Base	3	4	4	4	4	5	5	5	6	N/A
Shell	2	2	2	2	2	2	2	3	4	N/A
TCPL	2	3	3	3	3	3	3	3	3	3
NEB	3	4	4	4	4	4	4	4	4	4
Waste Wood and Pulping Liquor										
Gulf	9	10	10	10	10	10	11	12	13	N/A
Shell	6	6	7	6	7	7	7	7	8	N/A
TCPL	4	2	2	2	2	2	2	2	2	2
NEB	3	4	5	6	7	7	8	8	8	8

Table A4-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Manitoba (Cont'd)					
Solar and Wood										
Gulf	2	2	2	2	2	2	2	3	6	N/A
Petro-Canada – Base	1	2	1	1	1	2	2	4	5	N/A
Shell	0	0	0	0	0	0	0	2	2	N/A
NEB	3	3	3	3	4	4	4	6	7	7
Total End Use										
Gulf	234	232	237	241	243	244	254	271	292	N/A
Petro-Canada – Base	219	220	231	231	230	228	228	241	273	N/A
Shell	228	216	216	211	212	212	214	227	241	N/A
TCPL	136	133	137	138	140	140	144	151	155	162
NEB	229	226	229	230	232	234	244	259	278	297
					Saskatchewan					
Electricity										
Gulf	31	32	34	35	35	35	39	47	54	N/A
Husky/NOVA	32	34	35	37	38	39	43	52	61	75
Petro-Canada – Base	31	36	43	49	56	63	84	116	146	N/A
Shell	30	30	31	30	31	31	32	35	39	N/A
TCPL	31	33	34	36	37	37	40	42	45	49
Saskatchewan	32	34	35	37	38	40	43	49	55	61
NEB	31	32	35	36	38	39	42	49	55	62
Oil Products										
Gulf	137	135	137	139	140	141	144	150	158	N/A
Husky/NOVA	141	139	143	147	147	148	155	169	186	202
Petro-Canada – Base	133	127	133	134	134	133	133	139	150	N/A
Shell	137	129	126	124	125	124	127	133	138	N/A
NEB	137	137	141	140	139	138	136	138	148	161
Natural Gas										
Gulf	95	92	96	97	99	99	102	107	116	N/A
Husky/NOVA	95	88	93	95	97	99	107	120	136	151
Petro-Canada – Base	95	86	99	107	117	126	150	179	203	N/A
Shell	94	94	96	94	94	95	97	105	113	N/A
TCPL	95	104	109	110	110	111	114	118	123	128
APMC	N/A	62	60	55	50	45	N/A	N/A	N/A	N/A
Saskatchewan	96	93	98	101	104	107	113	120	127	132
NEB	95	91	95	98	101	104	113	129	145	160
LPG										
Gulf	4	4	4	5	5	5	5	5	6	N/A
Petro-Canada – Base	4	4	4	5	5	5	5	5	4	N/A
Shell	4	4	4	4	4	4	5	5	5	N/A
Saskatchewan	4	4	4	4	4	4	4	5	5	5
NEB	4	3	3	4	4	4	4	5	6	6

Table A4-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Saskatchewan (Cont'd)					
Coal, Coke and Coke Oven Gas										
Gulf	6	6	7	7	7	7	7	8	9	N/A
Husky/NOVA	6	4	4	4	4	4	4	4	4	4
Petro-Canada – Base	2	2	2	2	2	2	2	2	1	N/A
Shell	7	6	7	6	7	7	7	8	9	N/A
TCPL	6	7	7	7	6	6	5	5	5	5
Saskatchewan	5	5	5	5	5	6	6	6	7	7
NEB	6	8	8	7	7	7	7	6	7	7
Waste Wood and Pulping Liquor										
Gulf	3	3	3	3	3	3	4	4	4	N/A
Petro-Canada – Base	3	4	4	5	5	5	6	7	8	N/A
Shell	8	9	10	9	10	10	11	12	13	N/A
TCPL	4	1	1	1	1	2	2	3	3	3
NEB	8	9	10	10	10	10	11	11	11	11
Solar and Wood										
Gulf	2	2	2	2	2	2	2	4	6	N/A
Husky/NOVA	0	0	0	0	0	0	0	1	3	4
Petro-Canada – Base	0	0	0	1	1	1	2	3	4	N/A
Shell	0	0	0	0	0	0	1	2	3	N/A
NEB	2	2	2	2	2	2	3	4	5	7
Total End Use										
Gulf	278	274	283	287	291	292	302	324	353	N/A
Husky/NOVA	275	265	276	283	285	291	310	346	390	437
Petro-Canada – Base	271	262	290	305	322	339	387	456	524	N/A
Shell	280	272	273	269	271	271	280	299	320	N/A
NEB	282	281	294	297	300	304	316	342	377	414
					Alberta					
Electricity										
Gulf	89	86	90	93	97	99	108	134	166	N/A
Husky/NOVA	91	91	91	90	89	90	94	111	132	148
Imperial	91	93	101	109	116	123	143	181	213	N/A
Petro-Canada – Base	89	91	100	105	111	117	139	185	236	N/A
Shell	89	89	91	91	93	96	105	124	143	N/A
EUPC	82	87	94	99	106	110	128	150	181	206
NEB	89	93	94	98	101	106	118	140	167	194
Oil Products										
Gulf	345	329	341	364	373	377	410	457	511	N/A
Husky/NOVA	365	347	361	375	383	395	440	518	612	712
Imperial	344	340	347	359	363	365	369	370	351	N/A
Petro-Canada – Base	342	325	336	354	360	364	378	416	461	N/A
Shell	345	337	351	353	359	361	376	418	440	N/A
NEB	345	340	341	337	335	333	330	341	369	394

Table A4-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
				Alberta (Cont'd)						
Natural Gas										
Amoco	525	490	540	590	610	630	690	800	N/A	N/A
Gulf	409	507	520	535	546	554	606	650	725	N/A
Husky/NOVA	490	479	497	508	518	540	580	658	748	832
Imperial	502	541	586	601	611	617	627	667	684	N/A
Petro-Canada – Base	499	453	487	591	600	610	673	745	814	N/A
Shell	469	489	540	548	567	586	655	729	804	N/A
TCPL	490	603	650	743	775	897	958	1054	1157	1259
APMC	N/A	701	778	805	830	860	N/A	N/A	N/A	N/A
NEB	490	473	502	525	528	537	578	657	721	791
Ethane										
Amoco	22	34	37	53	69	85	101	133	133	133
Gulf	31	37	55	71	82	84	123	129	136	N/A
Husky/NOVA	21	33	48	70	76	79	115	126	126	126
Imperial	24	28	39	60	71	73	73	110	135	N/A
Shell	22	27	51	70	70	109	122	122	122	N/A
NEB	22	35	49	73	75	75	75	108	115	115
LPG										
Gulf	21	20	21	21	21	21	22	24	25	N/A
Imperial	19	20	23	23	23	23	32	32	33	N/A
Petro-Canada – Base	17	14	17	16	16	16	15	15	15	N/A
Shell	14	15	15	16	16	16	17	19	20	N/A
NEB	21	18	19	19	21	21	23	25	28	31
Coal, Coke and Coke Oven Gas										
Gulf	2	2	2	2	2	2	2	2	2	N/A
Husky/NOVA	2	1	1	1	1	1	1	1	1	1
Imperial	2	0	0	0	0	0	0	0	0	N/A
Petro-Canada – Base	2	2	1	1	1	1	1	0	0	N/A
Shell	1	0	0	0	1	1	3	6	11	N/A
NEB	3	1	1	1	1	1	1	1	1	1
Waste Wood and Pulping Liquor										
Gulf	11	12	12	12	12	12	12	13	15	N/A
Husky/NOVA	20	22	24	26	27	29	34	45	61	84
Imperial	24	30	31	33	34	35	38	45	52	N/A
Petro-Canada – Base	17	20	17	16	15	14	12	11	13	N/A
Shell	7	7	8	8	8	9	10	12	14	N/A
NEB	13	14	15	15	15	15	16	17	17	17
Solar and Wood										
Gulf	0	0	0	0	0	0	1	8	18	N/A
Imperial	1	1	1	1	1	1	1	3	8	N/A
Petro-Canada – Base	1	2	2	3	4	5	8	13	19	N/A
Shell	0	0	0	0	0	0	2	4	8	N/A
NEB	1	1	1	1	1	1	1	1	1	1

Table A4-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Alberta (Cont'd)					
Total End Use										
Gulf	990	992	1041	1098	1133	1150	1284	1417	1598	N/A
Husky/NOVA	990	973	1022	1070	1096	1134	1263	1458	1680	1903
Imperial	1011	1057	1132	1187	1219	1237	1203	1407	1474	N/A
Petro-Canada	1009	948	1015	1192	1213	1234	1374	1537	1708	N/A
Shell	948	964	1056	1085	1113	1179	1290	1434	1564	N/A
NEB	986	976	1022	1069	1077	1089	1141	1291	1419	1546
					British Columbia and Territories					
Electricity										
CPA	167	N/A	N/A	N/A	N/A	N/A	198	222	N/A	N/A
Gulf	145	144	153	158	161	163	176	197	222	N/A
Husky/NOVA	142	141	148	152	156	162	178	206	237	267
Imperial	142	145	153	159	166	173	185	207	222	N/A
Petro-Canada – Base	143	144	159	185	189	196	221	276	350	N/A
Shell	142	144	147	145	147	149	155	169	191	N/A
NEB	145	144	153	158	163	167	181	213	252	289
Oil Products										
CPA	361	N/A	N/A	N/A	N/A	N/A	381	401	N/A	N/A
Gulf	363	330	332	339	344	342	351	365	384	N/A
Husky/NOVA	349	337	350	362	366	375	405	464	530	588
Imperial	341	318	318	316	314	315	316	306	286	N/A
Petro-Canada – Base	363	326	330	333	328	323	308	314	326	N/A
Shell	355	351	351	341	342	341	340	359	377	N/A
NEB	363	325	323	324	317	317	320	335	357	385
Natural Gas										
CPA	191	N/A	N/A	N/A	N/A	N/A	226	231	N/A	N/A
Gulf	163	166	188	195	196	197	198	222	244	N/A
Husky/NOVA	163	158	169	176	183	191	212	245	279	315
Imperial	179	170	186	189	196	201	226	234	246	N/A
Petro-Canada – Base	162	170	213	251	264	274	283	293	312	N/A
Shell	160	173	178	178	184	190	210	235	259	N/A
TCPL	163	176	181	189	203	209	221	241	259	278
NEB	163	162	170	175	189	204	228	266	304	342
LPG										
Gulf	8	9	10	11	11	11	12	13	15	N/A
Imperial	7	7	7	8	8	8	11	11	11	N/A
Petro-Canada – Base	5	5	6	6	6	6	6	7	8	N/A
Shell	7	7	7	7	7	7	7	8	9	N/A
NEB	8	9	10	10	10	10	11	13	14	16

Table A4-2 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
				British Columbia and Territories (Cont'd)						
Coal, Coke and Coke Oven Gas										
CPA	2	N/A	N/A	N/A	N/A	N/A	7	8	N/A	N/A
Gulf	2	2	2	4	4	4	5	5	6	N/A
Husky/NOVA	3	4	5	5	5	5	6	6	7	7
Imperial	3	4	5	6	8	10	10	11	13	N/A
Petro-Canada – Base	2	2	2	2	2	2	1	1	1	N/A
Shell	7	6	6	6	6	6	7	7	8	N/A
NEB	3	3	3	3	3	3	3	4	4	5
Waste Wood and Pulping Liquor										
CPA	143	N/A	N/A	N/A	N/A	N/A	205	239	N/A	N/A
Gulf	149	159	165	167	171	172	194	228	254	N/A
Husky/NOVA	154	149	161	170	178	185	206	246	293	347
Imperial	153	150	158	166	172	178	197	226	259	N/A
Petro-Canada – Base	148	143	109	108	89	74	51	37	37	N/A
Shell	119	123	129	127	128	129	133	157	178	N/A
NEB	194	203	212	216	220	223	235	236	236	236
Solar and Wood										
Gulf	0	0	0	0	0	0	1	5	11	N/A
Imperial	4	4	5	5	4	4	3	6	13	N/A
Petro-Canada – Base	0	1	1	1	2	2	4	8	13	N/A
Shell	0	0	0	0	0	0	3	4	7	N/A
NEB	13	13	13	14	15	16	19	22	25	28
Total End Use										
CPA	863	N/A	N/A	N/A	N/A	N/A	1016	1101	N/A	N/A
Gulf	838	818	859	882	895	898	943	1044	1144	N/A
Husky/NOVA	810	788	833	865	888	918	1007	1167	1345	1525
Imperial	830	800	832	849	867	888	947	1000	1050	N/A
Petro-Canada – Base	823	791	820	886	880	877	876	938	1048	N/A
Shell	791	806	819	806	815	823	855	941	1031	N/A
NEB	888	859	885	899	916	940	997	1089	1193	1302

Table A4-3
Relative Energy Prices by Region
NEB Projection

(Percent)

	1982	1983	1985	1990	2000	2005
		Atlantic				
Residential						
Natural Gas/Electricity	69	66	61	55	57	60
Light Fuel Oil/Electricity	90	87	81	82	91	100
Natural Gas/Light Fuel Oil	76	76	75	67	62	61
Commercial						
Natural Gas/Electricity	73	79	75	44	49	52
Light Fuel Oil/Electricity	61	59	55	57	68	74
Natural Gas/Light Fuel Oil	118	133	136	76	72	71
Natural Gas/Heavy Fuel Oil	150	158	156	97	91	89
Industrial						
Natural Gas/Electricity	80	78	72	77	90	98
Heavy Fuel Oil/Electricity	84	88	85	80	97	106
Natural Gas/Heavy Fuel Oil	95	89	85	96	93	92
		Quebec				
Residential						
Natural Gas/Electricity	77	78	79	83	84	90
Light Fuel Oil/Electricity	107	108	111	121	134	146
Natural Gas/Light Fuel Oil	71	72	71	69	63	62
Commercial						
Natural Gas/Electricity	79	85	81	83	92	98
Light Fuel Oil/Electricity	106	107	102	106	125	136
Natural Gas/Light Fuel Oil	74	79	79	78	74	72
Natural Gas/Heavy Fuel Oil	106	110	111	109	103	100
Industrial						
Natural Gas/Electricity	81	82	77	80	94	103
Heavy Fuel Oil/Electricity	76	85	81	85	102	112
Natural Gas/Heavy Fuel Oil	107	97	95	95	92	91
		Ontario				
Residential						
Natural Gas/Electricity	71	76	67	66	68	73
Light Fuel Oil/Electricity	114	109	99	100	112	123
Natural Gas/Light Fuel Oil	63	69	68	66	61	59
Commercial						
Natural Gas/Electricity	63	70	63	64	74	79
Light Fuel Oil/Electricity	99	100	90	94	112	122
Natural Gas/Light Fuel Oil	64	70	70	68	66	65
Natural Gas/Heavy Fuel Oil	90	96	95	94	89	87

Table A4-3 (Cont'd)

	1982	1983	1985	1990	2000	2005
		Ontario (Cont'd)				
Industrial						
Natural Gas/Electricity	54	57	51	54	64	70
Heavy Fuel Oil/Electricity	57	62	58	61	75	83
Natural Gas/Heavy Fuel Oil	95	93	88	87	86	85
		Manitoba				
Residential						
Natural Gas/Electricity	75	88	78	78	83	91
Light Fuel Oil/Electricity	143	153	140	143	161	178
Natural Gas/Light Fuel Oil	52	57	56	55	52	51
Commercial						
Natural Gas/Electricity	67	71	64	67	79	86
Light Fuel Oil/Electricity	132	134	124	130	155	170
Natural Gas/Light Fuel Oil	51	53	52	52	51	51
Natural Gas/Heavy Fuel Oil	62	71	71	71	68	67
Industrial						
Natural Gas/Electricity	86	87	78	83	104	116
Heavy Fuel Oil/Electricity	123	126	113	120	149	166
Natural Gas/Heavy Fuel Oil	70	69	69	69	70	70
		Saskatchewan				
Residential						
Natural Gas/Electricity	42	47	42	42	46	51
Light Fuel Oil/Electricity	102	109	102	103	115	126
Natural Gas/Light Fuel Oil	41	43	41	40	40	41
Commercial						
Natural Gas/Electricity	40	40	36	38	47	52
Light Fuel Oil/Electricity	99	100	96	98	116	126
Natural Gas/Light Fuel Oil	40	40	38	39	41	41
Natural Gas/Heavy Fuel Oil	46	47	46	46	47	48
Industrial						
Natural Gas/Electricity	37	38	34	36	46	52
Heavy Fuel Oil/Electricity	71	72	66	70	85	94
Natural Gas/Heavy Fuel Oil	52	52	51	52	54	55
		Alberta				
Residential						
Natural Gas/Electricity	39	44	40	39	40	43
Light Fuel Oil/Electricity	107	98	91	92	102	112
Natural Gas/Light Fuel Oil	36	45	44	43	39	39
Commercial						
Natural Gas/Electricity	24	30	28	29	33	36
Light Fuel Oil/Electricity	68	74	69	72	85	93
Natural Gas/Light Fuel Oil	36	41	40	40	39	39
Natural Gas/Heavy Fuel Oil	41	47	47	46	45	44

Table A4-3 (Cont'd)

	1982	1983	1985	1990	2000	2005
		Alberta (Cont'd)				
Industrial						
Natural Gas/Electricity	28	28	26	27	31	37
Heavy Fuel Oil/Electricity	81	79	73	76	86	102
Natural Gas/Heavy Fuel Oil	34	35	35	35	36	36
		British Columbia				
Residential						
Natural Gas/Electricity	59	59	52	57	59	63
Light Fuel Oil/Electricity	113	109	96	92	102	112
Natural Gas/Light Fuel Oil	52	54	54	62	58	56
Commercial						
Natural Gas/Electricity	54	53	47	56	63	67
Light Fuel Oil/Electricity	91	92	81	80	94	103
Natural Gas/Light Fuel Oil	59	57	58	70	67	66
Natural Gas/Heavy Fuel Oil	87	81	81	98	93	91
Industrial						
Natural Gas/Electricity	53	49	43	55	66	72
Heavy Fuel Oil/Electricity	63	68	63	63	76	83
Natural Gas/Heavy Fuel Oil	83	72	69	88	87	86

Table A4-4
Distribution of End Use Energy Demand by Fuel and Sector
Canada and Regions
NEB Projections

(Percent)

	1978	1983	1990	2005
		Canada		
Residential				
Electricity	23	29	35	40
Oil	39	24	15	9
Gas	30	36	38	38
Wood	5	8	9	8
Other	3	3	3	5
Total	**100**	**100**	**100**	**100**
Commercial				
Electricity	30	34	37	38
Oil	29	18	10	4
Gas	41	45	50	52
Other	0	3	3	6
Total	**100**	**100**	**100**	**100**
Industrial				
Electricity	22	25	28	32
Oil	17	8	5	3
Gas	27	26	30	34
Coal	11	11	11	11
Steam	0	3	1	1
Wood	14	19	18	13
Other	9	8	7	6
Total	**100**	**100**	**100**	**100**
Total End Use				
Electricity	15	18	21	24
Oil	52	43	35	30
Gas	22	25	29	31
Coal	4	4	4	4
Steam	0	1	0	1
Wood	6	7	8	6
Other	1	2	3	4
Total	**100**	**100**	**100**	**100**
		Atlantic		
Residential				
Electricity	18	24	34	47
Oil	68	49	33	14
Gas	0	0	3	9
Wood	11	24	27	23
Other	3	3	3	7
Total	**100**	**100**	**100**	**100**

Table A4-4 (Cont'd)

	1978	1983	1990	2005
		Atlantic (Cont'd)		
Commercial				
Electricity	25	31	33	37
Oil	75	64	59	33
Gas	0	0	2	20
Other	0	5	6	10
Total	**100**	**100**	**100**	**100**
Industrial				
Electricity	23	27	33	38
Oil	43	23	18	8
Gas	0	0	3	19
Wood	12	23	23	15
Other	22	27	23	20
Total	**100**	**100**	**100**	**100**
Total End Use				
Electricity	14	17	22	29
Oil	75	63	56	42
Gas	0	0	2	12
Wood	6	13	14	10
Other	5	7	6	7
Total	**100**	**100**	**100**	**100**
		Quebec		
Residential				
Electricity	31	43	57	63
Oil	55	36	15	6
Gas	5	8	13	15
Wood	8	11	12	11
Other	1	2	3	5
Total	**100**	**100**	**100**	**100**
Commercial				
Electricity	36	49	56	63
Oil	55	32	16	5
Gas	9	17	25	26
Other	0	2	3	6
Total	**100**	**100**	**100**	**100**
Industrial				
Electricity	37	42	47	50
Oil	28	16	9	7
Gas	11	18	21	25
Wood	8	13	13	9
Other	16	11	10	9
Total	**100**	**100**	**100**	**100**
Total End Use				
Electricity	23	30	37	41
Oil	65	51	38	31
Gas	6	10	14	17

Table A4-4 (Cont'd)

	1978	1983	1990	2005
Quebec (Cont'd)				
Wood	4	7	7	6
Other	2	2	4	5
Total	100	100	100	100
Ontario				
Residential				
Electricity	23	28	33	36
Oil	34	19	10	6
Gas	38	44	48	48
Wood	3	6	6	6
Other	2	3	3	4
Total	100	100	100	100
Commercial				
Electricity	33	34	36	36
Oil	23	10	4	1
Gas	44	55	58	58
Other	0	1	2	5
Total	100	100	100	100
Industrial				
Electricity	15	18	21	23
Oil	13	6	4	3
Gas	38	32	37	40
Coal	23	25	25	24
Steam	0	6	2	1
Wood	6	8	7	5
Other	5	5	4	4
Total	100	100	100	100
Total End Use				
Electricity	14	16	18	21
Oil	47	40	32	27
Gas	28	29	33	35
Coal	8	8	9	10
Steam	0	1	1	1
Wood	2	4	4	3
Other	1	2	3	3
Total	100	100	100	100
Manitoba				
Residential				
Electricity	25	34	37	40
Oil	25	16	11	8
Gas	42	42	43	41
Wood	6	5	6	7
Other	2	3	3	4
Total	100	100	100	100

Table A4-4 (Cont'd)

	1978	1983	1990	2005
		Manitoba (Cont'd)		
Commercial				
Electricity	33	28	27	27
Oil	12	9	4	2
Gas	55	58	63	62
Other	0	6	6	9
Total	100	100	100	100
Industrial				
Electricity	27	31	34	37
Oil	6	9	5	3
Gas	37	30	32	37
Wood	10	10	15	12
Other	20	20	14	11
Total	100	100	100	100
Total End Use				
Electricity	17	19	21	21
Oil	49	46	39	40
Gas	28	28	31	31
Wood	3	3	5	4
Other	3	4	4	4
Total	100	100	100	100
		Saskatchewan		
Residential				
Electricity	13	18	20	22
Oil	36	28	26	24
Gas	44	49	48	46
Wood	2	2	3	3
Other	5	3	3	5
Total	100	100	100	100
Commercial				
Electricity	27	28	29	29
Oil	7	6	4	2
Gas	66	64	64	63
Other	0	2	3	6
Total	100	100	100	100
Industrial				
Electricity	14	15	17	19
Oil	4	4	2	1
Gas	57	49	54	58
Wood	11	12	11	8
Other	14	20	16	14
Total	100	100	100	100

Table A4-4 (Cont'd)

	1978	1983	1990	2005
		Saskatchewan (Cont'd)		
Total End Use				
Electricity	10	11	13	15
Oil	51	49	43	39
Gas	34	32	36	39
Wood	3	4	4	3
Other	2	4	4	4
Total	100	100	100	100
		Alberta		
Residential				
Electricity	12	13	16	17
Oil	12	11	13	15
Gas	67	70	65	62
Wood	1	1	1	1
Other	8	5	5	5
Total	100	100	100	100
Commercial				
Electricity	16	24	23	25
Oil	3	3	1	0
Gas	81	69	72	70
Other	0	4	4	5
Total	100	100	100	100
Industrial				
Electricity	15	24	26	28
Oil	0	0	0	0
Gas	59	51	53	58
Wood	8	8	8	5
Other	18	17	13	9
Total	100	100	100	100
Total End Use				
Electricity	7	9	10	13
Oil	37	35	29	25
Gas	52	48	51	51
Wood	1	2	1	1
Other	3	6	9	10
Total	100	100	100	100
		British Columbia and Territories		
Residential				
Electricity	26	32	33	36
Oil	29	15	10	7
Gas	35	39	41	42
Wood	7	11	12	11
Other	3	3	4	4
Total	100	100	100	100

Table A4-4 (Cont'd)

	1978	1983	1990	2005
	British Columbia and Territories (Cont'd)			
Commercial				
Electricity	31	35	34	34
Oil	23	18	12	5
Gas	46	43	50	53
Other	0	4	4	8
Total	100	100	100	100
Industrial				
Electricity	19	19	22	29
Oil	9	5	2	2
Gas	15	16	18	24
Wood	47	51	50	38
Other	10	9	8	7
Total	100	100	100	100
Total End Use				
Electricity	16	17	18	22
Oil	44	38	32	30
Gas	17	19	23	26
Wood	22	25	25	19
Other	1	1	2	3
Total	100	100	100	100

Table A5-1
Electricity Demand Growth Rates[1]
Comparison of Submittors' Views

(Percent per year)

	1983–1990	1990–2005	1983–2005
Newfoundland			
Nfld. & Labrador Hydro[2]	7.9	2.5	4.2
NEB	4.8	3.7	4.0
New Brunswick			
NBEPC	3.8	2.2[3]	3.1[3]
NEB	4.8	3.8	4.1
Nova Scotia			
Provincial Government	2.4	2.4	2.4
NEB	5.0	3.6	4.1
Prince Edward Island			
Maritime Electric	1.6	2.1	2.0
NEB	4.6	3.5	3.9
Quebec			
Hydro-Québec	2.5[3]	2.0[3]	2.3[3]
NEB	4.0	2.6	3.0
Ontario			
Ontario Hydro[4]	3.3	2.3	2.6
NEB	3.1	2.3	2.5
Manitoba			
Manitoba Hydro	3.2	2.4	2.6
NEB	2.8	1.4	1.9
Saskatchewan			
SPC[5]	3.6	2.3	2.7
NEB	4.0	2.6	3.1
Alberta			
EUPC	5.7	3.2	4.0
NEB	3.5	3.4	3.4
British Columbia			
B.C. Hydro	3.8	3.0	3.2
NEB[6]	3.3	3.2	3.2

[1] End use demand (excludes own use and loss).
[2] Source: Submission of Government of Newfoundland and Labrador.
[3] Years may differ from those indicated.
[4] Source: 1984 Planning Load Forecast
[5] Source: Submission of Saskatchewan Department of Energy and Mines
[6] Includes Yukon and Northwest Territories

Table A5-2
Historical Data – Total Demand for Electricity by Sector – Canada

(Petajoules)

	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970
Residential	N/A	N/A	85.3	91.1	98.2	107.0	115.6	126.0	135.9	145.5	156.3
Commercial	N/A	N/A	58.0	66.9	77.1	85.9	96.9	104.0	114.6	130.1	143.0
Industrial	N/A	N/A	235.7	239.3	261.6	278.1	300.1	312.6	328.8	348.6	364.8
Transportation	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Own Use	N/A	N/A	38.9	39.9	45.2	47.8	51.1	54.1	57.0	57.9	64.1
Total	N/A	N/A	417.9	437.2	482.0	518.7	563.7	596.7	636.4	682.2	728.2

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
Residential	167.5	180.7	194.4	213.4	230.8	254.8	275.7	310.3	315.4	333.6	342.3
Commercial	156.0	186.7	205.0	223.2	234.1	257.7	263.3	250.5	265.6	261.3	270.5
Industrial	375.2	390.9	417.1	435.5	392.0	405.8	447.7	470.1	476.7	503.9	523.9
Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8	1.6	1.9	2.5
Own Use	66.2	75.1	80.6	89.9	100.2	106.8	92.6	107.0	103.8	114.9	107.3
Total	764.8	833.3	897.2	961.9	957.1	1025.0	1079.4	1139.7	1163.1	1215.6	1246.5

Table A5-3
Total Demand for Electricity by Sector – Canada
NEB Projection

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Gigawatt hours										
Residential	99 271	102 296	105 123	108 021	110 801	114 304	124 613	139 115	152 922	163 637
Commercial	77 382	78 390	81 166	84 283	86 496	89 073	97 045	111 427	127 112	143 905
Industrial	136 221	141 083	152 412	160 250	165 722	171 630	190 115	225 637	265 616	303 061
Transportation	722	753	781	809	848	887	1 003	1 648	3 641	3 641
Own Use	31 644	33 677	34 829	36 716	38 229	39 854	41 921	48 263	54 658	60 995
Total	345 240	356 200	374 310	390 079	402 096	415 747	454 697	526 090	603 950	675 239
Petajoules										
Residential	357.4	368.3	378.4	388.9	398.9	411.5	448.6	500.8	550.5	589.1
Commercial	278.6	282.2	292.2	303.4	311.4	320.7	349.4	401.1	457.6	518.1
Industrial	490.4	507.9	548.7	576.9	596.6	617.9	684.4	812.3	956.2	1 091.0
Transportation	2.6	2.7	2.8	2.9	3.1	3.2	3.6	5.9	13.1	13.1
Own Use	113.9	121.2	125.4	132.2	137.6	143.5	150.9	173.7	196.8	219.6
Total	1 242.9	1 282.3	1 347.5	1 404.3	1 447.5	1 496.7	1 636.9	1 893.9	2 174.2	2 430.9

Demand data provided by NEB for 1982 are published actuals and for 1983 data were tracked to established trends published in Statistics Canada monthly catalogues.

Table A5-4
Generating Capacity by Fuel Type – Canada and Provinces
NEB Projection

Type of Capacity	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
				Canada (Gigawatts)						
Fossil Fuelled Steam										
Coal	16.0	16.4	16.6	17.1	17.0	16.7	18.4	20.0	22.7	26.0
Oil	3.6	3.6	3.6	3.6	3.6	3.6	2.7	2.6	2.5	2.3
Gas	3.4	3.4	3.5	2.9	2.9	2.9	3.0	3.3	3.2	3.2
Multi-fuelled	.5									
Other		.5	.5	.5	.6	.6	.6	.7	.8	.8
Other Fossil Fuelled										
Comb. Turbines	1.8	2.3	2.4	2.5	2.5	2.5	2.6	3.8	4.8	5.0
Int. Combustion	.6	.6	.6	.6	.6	.6	.6	.6	.7	.7
Nuclear	6.0	7.6	9.8	10.3	11.1	12.6	13.5	17.6	19.4	22.7
Hydro/Pumped Storage	50.0	50.1	55.1	56.2	56.2	56.2	58.9	68.9	79.5	86.4
Total Installed Capacity	81.9	84.5	92.1	93.7	94.5	95.7	100.4	117.5	133.6	147.1
Purchases										
Capacity Available	81.9	84.5	92.1	93.7	94.5	95.7	108.4	117.5	133.6	147.1
Sales (Export)	5.7	6.5	6.3	8.3	8.8	8.6	8.5	6.9	6.6	6.4
Domestic Peak Demand	61.9	63.1	67.9	70.7	72.9	75.4	82.6	95.8	110.1	123.1
System Peak Demand[1]	67.6	69.6	74.2	79.0	81.7	84.0	91.1	102.7	116.7	129.5
Remaining Capacity	14.3	14.9	17.9	14.7	12.8	11.7	9.3	14.8	16.9	17.6
% of System Peak	21.2	21.4	24.1	18.6	15.7	13.9	10.2	14.4	14.5	13.6
				Newfoundland and Labrador (Megawatts)						
Fossil Fuelled Steam										
Coal										
Oil	479.0	466.0	466.0	466.0	466.0	468.0	468.0	471.0	476.0	476.0
Gas										
Multi-fuelled										
Other								15.0	20.0	20.0
Other Fossil Fuelled										
Comb. Turbines	163.0	217.0	271.0	271.0	271.0	271.0	421.0	421.0	421.0	421.0
Int. Combustion	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
Nuclear										
Hydro/Pumped Storage	6681.0	6681.0	6708.0	6835.0	6835.0	6835.0	6835.0	8543.0	8543.0	8543.0
Total Installed Capacity	7404.0	7445.0	7526.0	7653.0	7653.0	7655.0	7805.0	9531.0	9541.0	9541.0
Purchases										
Capacity Available	7404.0	7445.0	7526.0	7653.0	7653.0	7655.0	7805.0	9531.0	9541.0	9541.0
Sales	5225.0	5225.0	5225.0	5225.0	5223.0	5221.0	5215.0	5205.0	5195.0	5185.0
Domestic Peak Demand	1578.0	1614.0	1784.0	1866.0	1938.0	2053.0	2261.0	2819.0	3392.0	3869.0
System Peak Demand	6803.0	6839.0	7009.0	7091.0	7161.0	7274.0	7476.0	8024.0	8587.0	9054.0
Remaining Capacity	601.0	606.0	517.0	562.0	492.0	381.0	329.0	1507.0	954.0	487.0
(%) of Domestic Peak[2]	N/A	N/A	29.0	30.1	25.4	18.6	14.6	53.5	28.1	12.6

Table A5-4 (Cont'd)

Type of Capacity	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
				Nova Scotia (Megawatts)						
Fossil Fuelled Steam										
Coal	718.0	718.0	718.0	861.0	861.0	861.0	861.0	1761.0	2361.0	2961.0
Oil	785.0	763.0	763.0	763.0	763.0	763.0	728.0	624.0	530.0	385.0
Gas							25.0	40.0	40.0	40.0
Multi-fuelled										
Other		22.0	22.0	22.0	22.0	22.0	32.0	37.0	37.0	37.0
Other Fossil Fuelled										
Comb. Turbines	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Int. Combustion	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Nuclear										
Hydro-Pumped Storage	354.0	374.0	374.0	374.0	374.0	374.0	374.0	374.0	374.0	374.0
Total Installed Capacity	2063.0	2083.0	2083.0	2226.0	2226.0	2226.0	2226.0	3042.0	3548.0	4003.0
Purchases										
Capacity Available	2063.0	2083.0	2083.0	2226.0	2226.0	2226.0	2226.0	3042.0	3548.0	4003.0
Sales										
Domestic Peak Demand	1219.0	1258.0	1294.0	1363.0	1420.0	1494.0	1667.0	2057.0	2528.0	2909.0
System Peak Demand	1219.0	1258.0	1294.0	1363.0	1420.0	1494.0	1667.0	2057.0	2528.0	2909.0
Remaining Capacity	844.0	825.0	789.0	863.0	806.0	732.0	559.0	985.0	1020.0	1094.0
(%) of System Peak	69.2	65.6	61.0	63.3	56.8	49.0	33.5	47.9	40.3	37.6
				Prince Edward Island (Megawatts)						
Fossil Fuelled Steam										
Coal							45.0	90.0	135.0	135.0
Oil	67.0	67.0	67.0	67.0	67.0	67.0	67.0	67.0	67.0	67.0
Gas										
Multi-fuelled										
Other										
Other Fossil Fuelled										
Comb. Turbines	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Int. Combustion	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Nuclear										
Hydro/Pumped Storage										
Total Installed Capacity	110.0	110.0	110.0	110.0	110.0	110.0	155.0	200.0	245.0	245.0
Purchases	22.0	27.0	31.0	36.0	42.0	49.0	42.0	31.0	28.0	74.0
Capacity Available	132.0	137.0	141.0	146.0	152.0	159.0	197.0	231.0	273.0	319.0
Sales										
Domestic Peak Demand	110.0	115.0	119.0	124.0	129.0	135.0	152.0	186.0	228.0	275.0
System Peak Demand	110.0	115.0	119.0	124.0	129.0	135.0	152.0	186.0	228.0	275.0
Remaining Capacity	22.0	22.0	22.0	22.0	23.0	24.0	45.0	45.0	45.0	44.0
(%) of System Peak	20.0	19.1	18.5	17.7	17.8	17.8	29.6	24.2	19.7	16.0

Table A5-4 (Cont'd)

Type of Capacity	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
New Brunswick (Megawatts)										
Fossil Fuelled Steam										
Coal	282.0	282.0	282.0	282.0	282.0	532.0	1032.0	1032.0	1032.0	1032.0
Oil	1464.0	1443.0	1443.0	1443.0	1443.0	1513.0	665.0	637.0	637.0	637.0
Gas							13.0	251.0	351.0	351.0
Multi-fuelled	73.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
Other		61.0	61.0	61.0	61.0	76.0	76.0	86.0	86.0	86.0
Other Fossil Fuelled										
Comb. Turbines	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	226.0
Int. Combustion	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Nuclear	630.0	630.0	630.0	630.0	630.0	630.0	630.0	1890.0	1890.0	2520.0
Hydro/Pumped Storage	891.0	895.0	895.0	895.0	895.0	895.0	895.0	1055.0	1055.0	1055.0
Total Installed Capacity	3367.0	3371.0	3371.0	3371.0	3371.0	3706.0	3371.0	5011.0	5111.0	5941.0
Purchases										
Capacity Available	3367.0	3371.0	3371.0	3371.0	3371.0	3706.0	3371.0	5011.0	5111.0	5941.0
Sales	155.0	390.0	494.0	499.0	502.0	379.0	372.0	891.0	658.0	704.0
Domestic Peak Demand	1633.0	1685.0	2000.0	2114.0	2194.0	2318.0	2534.0	3169.0	3775.0	4267.0
System Peak Demand	1788.0	2075.0	2494.0	2613.0	2696.0	2697.0	2906.0	4060.0	4433.0	4971.0
Remaining Capacity	1579.0	1296.0	877.0	758.0	675.0	1009.0	465.0	951.0	678.0	970.0
(%) of System Peak	88.3	62.5	35.2	29.0	25.0	37.4	16.0	23.4	15.3	19.5
Quebec (Megawatts)										
Fossil Fuelled Steam										
Coal										
Oil	666.0	666.0	666.0	648.0	648.0	640.0	640.0	640.0	640.0	640.0
Gas				18.0	18.0	18.0	18.0	18.0	18.0	18.0
Multi-fuelled										
Other	13.0	13.0	13.0	13.0	13.0	21.0	21.0	21.0	21.0	21.0
Other Fossil Fuelled										
Comb. Turbines	402.0	402.0	466.0	466.0	466.0	466.0	466.0	1666.0	2676.0	2676.0
Int. Combustion	137.0	179.0	142.0	146.0	146.0	146.0	177.0	218.0	253.0	253.0
Nuclear		200.0	637.0	637.0	637.0	637.0	637.0	637.0	637.0	637.0
Hydro/Pumped Storage	20419.0	20369.0	23620.0	24284.0	24284.0	24284.0	26966.0	29544.0	36922.0	40682.0
Total Installed Capacity	21637.0	21829.0	25544.0	26212.0	26212.0	26212.0	28925.0	32744.0	41167.0	44927.0
Purchases	5225.0	5225.0	5225.0	5225.0	5223.0	5221.0	5215.0	5205.0	5195.0	5185.0
Capacity Available	26862.0	27054.0	30769.0	31437.0	31435.0	31433.0	34140.0	37949.0	46362.0	50112.0
Sales	93.0	95.0	108.0	108.0	56.0	56.0	56.0	56.0		
Domestic Peak Demand	22049.0	22214.0	23745.0	24879.0	25663.0	26700.0	29413.0	34165.0	39113.0	43616.0
System Peak Demand	22142.0	22309.0	23853.0	24987.0	25719.0	26756.0	29469.0	34221.0	39113.0	43616.0
Remaining Capacity	4720.0	4745.0	6916.0	6450.0	5716.0	4677.0	4671.0	3728.0	7249.0	6496.0
(%) of System Peak	21.3	21.3	29.0	25.8	22.2	17.5	15.9	10.9	18.5	14.9

Table A5-4 (Cont'd)

Type of Capacity	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Ontario (Megawatts)										
Fossil Fuelled Steam										
Coal	9657	9657	9775	9775	9332	8741	8771	8801	9969	10969
Oil	35	85	85	85	65	65	65	65	65	65
Gas	706	706	706	118	158	158	188	218	248	248
Multi-fuelled	86									
Other		35	35	35	55	55	85	115	145	145
Other Fossil Fuelled										
Comb. Turbines	543	726	726	816	816	816	816	816	816	816
Int. Combustion	10	10	10	10	10	10	10	10	10	10
Nuclear	5323	6796	8514	9030	9786	11337	12218	15088	16850	19493
Hydro/Pumped Storage	7119	7207	7207	7207	7207	7207	7207	8939	9089	9089
Total Installed Capacity	23479	25222	27058	27076	27429	28389	29360	34052	37192	40835
Purchases										
Capacity Available	23479	25222	27058	27076	27429	28389	29360	34052	37192	40835
Sales	143	655	467	447	447	447	400			
Domestic Peak Demand	17949	18807	20494	21225	21792	22374	24385	27478	30911	33972
System Peak Demand	18092	19462	20961	21672	22239	22821	24785	27478	30911	33972
Remaining Capacity	5387	5760	6097	5404	5190	5568	4575	6574	6281	6863
(%) of System Peak	29.7	29.5	29.1	24.9	23.3	24.3	18.4	23.9	20.3	20.2
Manitoba (Megawatts)										
Fossil Fuelled Steam										
Coal	358.0	358.0	358.0	358.0	358.0	358.0	358.0	358.0	358.0	358.0
Oil		19.0	19.0	14.0	14.0	10.0	10.0	10.0	10.0	10.0
Gas	4.0	4.0	141.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0
Multi-fuelled	24.0									
Other		5.0	5.0	5.0	5.0	9.0	9.0	9.0	9.0	9.0
Other Fossil Fuelled										
Comb. Turbines										
Int. Combustion	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0
Nuclear										
Hydro/Pumped Storage	3644.0	3644.0	3644.0	3644.0	3644.0	3644.0	3644.0	4814.0	4814.0	4814.0
Total Installed Capacity	4061.0	4061.0	4198.0	4198.0	4198.0	4198.0	4198.0	5368.0	5368.0	5368.0
Purchases	374.0	374.0	300.0	300.0	300.0	300.0	300.0			
Capacity Available	4435.0	4435.0	4498.0	4498.0	4498.0	4498.0	4498.0	5368.0	5368.0	5368.0
Sales								500.0	500.0	500.0
Domestic Peak Demand	2684.0	2767.0	2986.0	3033.0	3101.0	3169.0	3365.0	3761.0	3980.0	4162.0
System Peak Demand	2684.0	2767.0	2986.0	3033.0	3101.0	3169.0	3365.0	4261.0	4480.0	4662.0
Remaining Capacity	1751.0	1668.0	1512.0	1465.0	1397.0	1329.0	1133.0	1107.0	888.0	706.0
(%) of System Peak	65.2	60.3	50.6	48.3	45.0	41.9	33.7	26.0	19.8	15.1

Table A5-4 (Cont'd)

Type of Capacity	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Saskatchewan (Megawatts)										
Fossil Fuelled Steam										
Coal	1586.0	1586.0	1586.0	1586.0	1586.0	1587.0	1886.0	2486.0	2786.0	2786.0
Oil		5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Gas	362.0	338.0	287.0	287.0	287.0	287.0	297.0	307.0	307.0	307.0
Multi-fuelled	21.0									
Other		39.0	39.0	39.0	39.0	39.0	44.0	49.0	49.0	49.0
Other Fossil Fuelled										
Comb. Turbines										
Int. Combustion	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Nuclear										
Hydro/Pumped Storage	589.0	589.0	589.0	841.0	841.0	841.0	841.0	846.0	846.0	1396.0
Total Installed Capacity	2568.0	2567.0	2516.0	2768.0	2768.0	2769.0	3083.0	3703.0	4003.0	4553.0
Purchases										
Capacity Available	2568.0	2567.0	2516.0	2768.0	2768.0	2769.0	3083.0	3703.0	4003.0	4553.0
Sales	74.0	74.0								
Domestic Peak Demand	1984.0	2048.0	2244.0	2332.0	2398.0	2469.0	2689.0	3091.0	3483.0	3851.0
System Peak Demand	2058.0	2122.0	2244.0	2332.0	2398.0	2469.0	2689.0	3091.0	3483.0	3851.0
Remaining Capacity	510.0	445.0	272.0	436.0	370.0	300.0	394.0	612.0	520.0	702.0
(%) of System Peak	24.8	21.0	12.1	18.7	15.4	12.2	14.7	19.8	14.9	18.2
Alberta (Megawatts)										
Fossil Fuelled Steam										
Coal	3399.0	3762.0	3836.0	4219.0	4602.0	4602.0	5414.0	5494.0	6094.0	7766.0
Oil		4.0	4.0	4.0	4.0	4.0	2.0	2.0	2.0	2.0
Gas	1345.0	1391.0	1391.0	1392.0	1355.0	1355.0	1357.0	1232.0	1077.0	1077.0
Multi-fuelled	87.0									
Other		115.0	115.0	115.0	115.0	115.0	120.0	125.0	135.0	135.0
Other Fossil Fuelled										
Comb. Turbines	5.0	193.0	193.0	193.0	193.0	193.0	193.0	193.0	193.0	193.0
Int. Combustion	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
Nuclear										
Hydro/Pumped Storage	801.0	801.0	801.0	801.0	801.0	801.0	801.0	2301.0	3351.0	3351.0
Total Installed Capacity	5669.0	6298.0	6372.0	6756.0	7102.0	7102.0	7919.0	9379.0	10884.0	12556.0
Purchases										
Capacity Available	5669.0	6298.0	6372.0	6756.0	7102.0	7102.0	7919.0	9379.0	10884.0	12556.0
Sales					500.0	500.0	500.0			
Domestic Peak Demand	4625.0	4691.0	5149.0	5346.0	5590.0	5810.0	6490.0	7712.0	9189.0	10619.0
System Peak Demand	4625.0	4691.0	5149.0	5346.0	6090.0	6310.0	6990.0	7712.0	9189.0	10619.0
Remaining Capacity	1044.0	1607.0	1223.0	1410.0	1012.0	792.0	929.0	1667.0	1695.0	1937.0
(%) of System Peak	22.6	34.3	23.8	26.4	16.6	12.6	13.3	21.6	18.4	18.2

Table A5-4 (Cont'd)

Type of Capacity	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
British Columbia (Megawatts)										
Fossil Fuelled Steam										
Coal										
Oil	87.0	87.0	87.0	87.0	87.0	87.0	87.0	47.0	47.0	47.0
Gas	969.0	984.0	984.0	984.0	984.0	984.0	999.0	1039.0	1039.0	1039.0
Multi-fuelled	227.0									
Other		240.0	240.0	240.0	240.0	240.0	255.0	255.0	275.0	275.0
Other Fossil Fuelled										
Comb. Turbines	448.0	448.0	448.0	448.0	448.0	448.0	448.0	448.0	448.0	448.0
Int. Combustion	45.0	45.0	45.0	45.0	45.0	45.0	45.0	30.0	30.0	30.0
Nuclear										
Hydro/Pumped Storage	9433.0	9378.0	11178.0	11178.0	11178.0	11178.0	11178.0	12551.0	14544.0	17071.0
Total Installed Capacity	11209.0	11182.0	12982.0	12982.0	12982.0	12982.0	13012.0	14370.0	16383.0	18910.0
Purchases					500.0	500.0	500.0			
Capacity Available	11209.0	11182.0	12982.0	12982.0	13482.0	13482.0	13512.0	14370.0	16383.0	18910.0
Sales	7.0	7.0	7.0	2000.0	2000.0	2000.0	2000.0	307.0	307.0	7.0
Domestic Peak Demand	7842.0	7766.0	7875.0	8224.0	8508.0	8706.0	9419.0	11082.0	13171.0	15227.0
System Peak Demand	7849.0	7773.0	7882.0	10224.0	10508.0	10706.0	11419.0	11389.0	13478.0	15234.0
Remaining Capacity	3360.0	3409.0	5100.0	2758.0	2974.0	2776.0	2093.0	2981.0	2905.0	3676.0
(%) of System Peak	42.8	43.9	64.7	27.0	28.3	25.9	18.3	26.2	21.6	24.1
Yukon (Megawatts)										
Fossil Fuelled Steam										
Coal										
Oil										
Gas										
Multi-fuelled										
Other										
Other Fossil Fuelled										
Comb. Turbines										
Int. Combustion	48.0	48.0	48.0	48.0	48.0	48.0	48.0	64.0	72.0	88.0
Nuclear										
Hydro/Pumped Storage	58.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	97.0	116.0
Total Installed Capacity	106.0	126.0	126.0	126.0	126.0	126.0	126.0	142.0	169.0	204.0
Purchases										
Capacity Available	106.0	126.0	126.0	126.0	126.0	126.0	126.0	142.0	169.0	204.0
Sales										
Domestic Peak Demand	85.0	85.0	81.0	85.0	88.0	90.0	97.0	113.0	134.0	154.0
System Peak Demand	85.0	85.0	81.0	85.0	88.0	90.0	97.0	113.0	134.0	154.0
Remaining Capacity	21.0	41.0	45.0	41.0	38.0	36.0	29.0	29.0	35.0	50.0
(%) of System Peak	24.7	48.2	55.6	48.2	43.2	40.0	29.9	25.7	26.1	32.5

Table A5-4 (Cont'd)

Type of Capacity	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Northwest Territories (Megawatts)					
Fossil Fuelled Steam										
Coal										
Oil										
Gas										
Multi-fuelled										
Other										
Other Fossil Fuelled										
Comb. Turbines										
Int. Combustion	147.0	147.0	154.0	154.0	154.0	154.0	154.0	154.0	161.0	168.0
Nuclear										
Hydro/Pumped Storage	43.0	43.0	43.0	43.0	43.0	53.0	53.0	53.0	53.0	88.0
Total Installed Capacity	190.0	190.0	197.0	197.0	197.0	207.0	207.0	207.0	214.0	256.0
Purchases										
Capacity Available	190.0	190.0	197.0	197.0	197.0	207.0	207.0	207.0	214.0	256.0
Sales										
Domestic Peak Demand	96.0	96.0	111.0	115.0	119.0	121.0	130.0	151.0	177.0	203.0
System Peak Demand	96.0	96.0	111.0	115.0	119.0	121.0	130.0	151.0	177.0	203.0
Remaining Capacity	94.0	94.0	86.0	82.0	78.0	86.0	77.0	56.0	37.0	53.0
(%) of System Peak	97.9	97.9	77.5	71.3	65.5	71.1	59.2	37.1	20.9	26.1

(1) This is a sum of non-coincident provincial system peak loads.

(2) Remaining Capacity is expressed as a percent of domestic peak for Newfoundland and Labrador, rather than a percent of system peak. As the Remaining Capacity only becomes meaningful after the Island is interconnected with sources in Labrador, no percentage is shown for 1982 and 1983. Labrador is currently interconnected only with Quebec.

Table A5-5
Energy Generation by Fuel Type – Canada and Provinces
NEB Projection

Type of Generation	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Canada (Terawatt hours)										
Coal Fired Steam										
–Bituminous	6.3	7.1	13.6	12.9	12.6	11.8	14.3	19.5	22.9	24.4
–Sub-Bituminous	53.5	53.2	55.9	43.5	48.5	51.6	51.9	51.4	50.3	61.6
–Lignite	8.2	8.2	9.0	9.2	8.4	8.6	9.7	11.9	14.1	13.9
Oil Fired Steam										
–Light	.3	.2								
–Heavy	8.4	4.4	5.7	7.0	4.8	6.8	8.4	1.0	1.5	1.1
Natural Gas Fired Steam	3.9	6.0	2.8	3.2	4.9	4.3	4.1	4.3	3.8	4.3
Gas Turbines										
–Light Oil			.8	.9	.9	.9	.9	1.3	1.8	1.9
–Diesel Oil	.1			.1	.1	.1	.1	.2	.2	.1
–Natural Gas	2.5	1.6	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Internal Combustion										
–Diesel Oil	.9	.8	.6	.6	.6	.6	.6	.7	.9	1.0
Nuclear	36.2	44.2	49.3	68.5	72.2	77.5	94.5	114.5	135.7	151.9
Hydroelectric	257.4	267.9	287.0	296.2	305.9	310.8	311.7	354.5	401.4	434.0
Other	2.2	2.2	2.2	2.3	2.4	2.6	3.0	3.4	4.0	4.0
Total Energy Generation	380.1	396.0	427.8	445.5	462.2	476.6	500.3	563.8	637.7	699.3
Total Domestic Consumption	348.4	359.7	374.4	390.1	402.1	415.8	454.7	526.2	604.0	675.3
Interprovincial Transfers										
Exports (Net)	31.7	36.3	53.4	55.4	60.1	60.8	45.6	37.6	33.7	24.0
Newfoundland (Gigawatt hours)										
Coal Fired Steam										
–Bituminous										
–Sub-Bituminous										
–Lignite										
Oil Fired Steam										
–Light	2.0	4.0								
–Heavy	1145.0	599.0	1515.0	1538.0	1147.0	1622.0	2697.0	69.0	114.0	114.0

Table A5-5 (Cont'd)

Type of Generation	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Newfoundland (Cont'd)					
Natural Gas Fired Steam										
Gas Turbines										
–Light Oil	8.0	4.0	76.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
–Diesel Oil										
–Natural Gas										
Internal Combustion										
–Diesel Oil	90.0		28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0
Nuclear										
Hydroelectric	43096.0	39516.0	43635.0	43822.0	44508.0	44508.0	44508.0	55866.0	55866.0	55866.0
Other						40.0	49.0	67.0	112.0	112.0
Total Energy Generation	44341.0	40123.0	45254.0	45488.0	45783.0	46298.0	47382.0	56130.0	56220.0	56220.0
Total Domestic Consumption	8563.0	8884.0	9583.0	10053.0	10466.0	10995.0	12186.0	14979.0	18128.0	20721.0
Interprovincial Transfers (Net)	35778.0	31239.0	35671.0	35435.0	35317.0	35303.0	35196.0	41151.0	38092.0	35499.0
Exports (Net)										
					Nova Scotia (Gigawatt hours)					
Coal Fired Steam										
–Bituminous	3133.0	2330.0	4557.0	4775.0	5495.0	5677.0	5715.0	9810.0	12456.0	14602.0
–Sub-Bituminous										
–Lignite										
Oil Fired Steam										
–Light	10.0	10.0								
–Heavy	2338.0	1449.0	757.0	1031.0	735.0	977.0	2086.0	71.0	77.0	77.0
Natural Gas Fired Steam							131.0	298.0	315.0	315.0
Gas Turbines										
–Light Oil	1.0	1.0	90.0	90.0	90.0	90.0	90.0			
–Diesel Oil										
–Natural Gas										
Internal Combustion										
–Diesel Oil										
Nuclear										
Hydroelectric	1025.0	997.0	1033.0	1033.0	1033.0	1033.0	1033.0	1033.0	1033.0	1033.0
Other	61.0	103.0	103.0	109.0	110.0	112.0	174.0	193.0	210.0	210.0

Table A5-5 (Cont'd)

Type of Generation	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Nova Scotia (Cont'd)										
Total Energy Generation	6568.0	4890.0	6540.0	7038.0	7463.0	7889.0	9229.0	11405.0	14091.0	16237.0
Total Domestic Consumption	6651.0	5565.0	7220.0	7618.0	7943.0	8369.0	9359.0	11535.0	14221.0	16367.0
Interprovincial Transfers (Net)	83.0	675.0	680.0	580.0	480.0	480.0	130.0	130.0	130.0	130.0
Exports (Net)										
Prince Edward Island (Gigawatt hours)										
Coal Fired Steam										
–Bituminous								301.0	627.0	881.0
–Sub-Bituminous										
–Lignite										
Oil Fired Steam										
–Light										
–Heavy	33.0	10.0	81.0	81.0	81.0	81.0	81.0	45.0	35.0	
Natural Gas Fired Steam										
Gas Turbines										
–Light Oil	1.0	1.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
–Diesel Oil										
–Natural Gas										
Internal Combustion										
–Diesel Oil			4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Nuclear										
Hydroelectric										
Other	1.0									
Total Energy Generation	35.0	11.0	100.0	100.0	100.0	100.0	100.0	365.0	681.0	900.0
Total Domestic Consumption	513.0	555.0	594.0	618.0	639.0	655.0	716.0	847.0	1003.0	1250.0
Interprovincial Transfers (Net)	–478.0	–544.0	–494.0	–518.0	–539.0	–555.0	–616.0	–482.0	–322.0	–350.0
Exports (Net)										

Table A5-5 (Cont'd)

Type of Generation	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
New Brunswick (Gigawatt hours)										
Coal Fired Steam										
–Bituminous	1289.0	1954.0	2117.0	2188.0	2145.0	2174.0	5480.0	6125.0	6358.0	5392.0
–Sub-Bituminous										
–Lignite										
Oil Fired Steam										
–Light	20.0									
–Heavy	3952.0	1423.0	2529.0	3586.0	2125.0	3419.0	2777.0	210.0	648.0	224.0
Natural Gas Fired Steam							142.0	464.0	801.0	661.0
Gas Turbines										
–Light Oil			11.0	11.0	11.0	11.0	11.0	11.0	11.0	99.0
–Diesel Oil										
–Natural Gas										
Internal Combustion										
–Diesel Oil										
Nuclear	254.0	4759.0	4415.0	4415.0	4415.0	4415.0	4415.0	13245.0	13245.0	17660.0
Hydroelectric	2645.0	3110.0	2777.0	2777.0	2777.0	2777.0	2777.0	2647.0	2647.0	2647.0
Other	275.0	294.0	294.0	297.0	299.0	373.0	376.0	382.0	388.0	388.0
Total Energy Generation	8435.0	11540.0	12143.0	13274.0	11772.0	13169.0	15978.0	23084.0	24098.0	27071.0
Total Domestic Consumption	8433.0	8623.0	9769.0	10363.0	10777.0	11419.0	12541.0	15796.0	18937.0	21484.0
Interprovincial Transfers (Net)	–2938.0	–2768.0	–2831.0	–2484.0	–4563.0	–4547.0	–2836.0	–1730.0	–1390.0	–458.0
Exports (Net)	2940.0	5685.0	5205.0	5395.0	5558.0	6297.0	6273.0	9018.0	6551.0	6045.0
Quebec (Gigawatt hours)										
Coal Fired Steam										
–Bituminous										
–Sub-Bituminous										
–Lignite										
Oil Fired Steam										
–Light										
–Heavy	24.0	12.0	12.0	11.0	11.0	6.0	23.0	23.0	23.0	23.0
Natural Gas Fired Steam				12.0	12.0	12.0	12.0	12.0	12.0	12.0

Table A5-5 (Cont'd)

Type of Generation	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Quebec (Cont'd)										
Gas Turbines										
–Light Oil			204.0	204.0	204.0	204.0	204.0	730.0	1172.0	1172.0
–Diesel Oil										
–Natural Gas										
Internal Combustion										
–Diesel Oil	203.0	222.0	73.0	74.0	76.0	76.0	76.0	90.0	108.0	123.0
Nuclear			4464.0	4464.0	4464.0	4464.0	4464.0	4464.0	4464.0	4464.0
Hydroelectric	99810.0	110322.0	117679.0	123803.0	131704.0	136603.0	136603.0	151683.0	174316.0	193296.0
Other		51.0	51.0	51.0	51.0	61.0	61.0	61.0	61.0	61.0
Total Energy Generation	100037.0	110607.0	122483.0	128619.0	136522.0	141426.0	141443.0	157063.0	180156.0	199151.0
Total Domestic Consumption	117826.0	122338.0	129438.0	135401.0	139518.0	144973.0	159243.0	184221.0	210223.0	233895.0
Interprovincial Transfers (Net)	–26325.0	–21958.0	–25167.0	–25283.0	–23165.0	–24403.0	–28544.0	–36988.0	–35432.0	–34744.0
Exports (Net)	8536.0	10277.0	18212.0	18501.0	20169.0	20856.0	10744.0	9840.0	5365.0	
Ontario (Gigawatt hours)										
Coal Fired Steam										
–Bituminous	1394.0	2284.0	6904.0	5896.0	4916.0	3952.0	3089.0	3245.0	3487.0	3487.0
–Sub-Bituminous	33414.0	32910.0	30851.0	17861.0	18847.0	19813.0	15179.0	14877.0	12987.0	15505.0
–Lignite	1600.0	911.0	1600.0	1400.0	1200.0	1000.0	1000.0	1000.0	1000.0	1000.0
Oil Fired Steam										
–Light	153.0	170.0								
–Heavy	345.0	529.0	354.0	381.0	272.0	296.0	305.0	319.0	340.0	340.0
Natural Gas Fired Steam	452.0	1186.0	1350.0	1350.0	1350.0	1350.0	1350.0	1350.0	1350.0	1350.0
Gas Turbines										
–Light Oil	14.0	15.0	238.0	238.0	277.0	277.0	277.0	277.0	277.0	277.0
–Diesel Oil										
–Natural Gas	1032.0									
Internal Combustion										
–Diesel Oil	4.0	4.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Nuclear	35899.0	39472.0	40394.0	59666.0	63282.0	68580.0	85624.0	96745.0	117974.0	129821.0
Hydroelectric	38751.0	40360.0	37968.0	37968.0	37968.0	37968.0	37968.0	40114.0	42865.0	43084.0
Other	123.0	148.0	148.0	161.0	240.0	261.0	393.0	559.0	783.0	783.0
Total Energy Generation	113181.0	117989.0	119809.0	124923.0	128354.0	133499.0	145187.0	158488.0	181065.0	195649.0
Total Domestic Consumption	109074.0	112428.0	114807.0	119096.0	122027.0	125422.0	136640.0	154143.0	173597.0	191025.0

Table A5-5 (Cont'd)

Type of Generation	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Ontario (Cont'd)					
Interprovincial Transfers (Net)	–6542.0	–6277.0	–6947.0	–6946.0	–6946.0	–5696.0	–3446.0	–2446.0	–1454.0	–454.0
Exports (Net)	10649.0	11838.0	11949.0	12773.0	13273.0	13773.0	11993.0	6791.0	8922.0	5078.0
					Manitoba (Gigawatt hours)					
Coal Fired Steam										
–Bituminous										
–Sub-Bituminous										
–Lignite	178.0	67.0								
Oil Fired Steam										
–Light										
–Heavy	30.0	51.0	51.0	38.0	38.0	26.0	26.0	26.0	26.0	26.0
Natural Gas Fired Steam	8.0	27.0	7.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Gas Turbines										
–Light Oil	12.0	7.0								
–Diesel Oil										
–Natural Gas										
Internal Combustion										
–Diesel Oil	52.0	52.0	16.0	16.0	16.0	16.0	16.0	16.0	22.0	22.0
Nuclear										
Hydroelectric	20495.0	21892.0	20630.0	20630.0	20630.0	20630.0	20630.0	27100.0	27100.0	27100.0
Other	26.0	14.0	14.0	14.0	14.0	26.0	26.0	26.0	26.0	26.0
Total Energy Generation	20801.0	22110.0	20718.0	20718.0	20718.0	20718.0	20718.0	27188.0	27194.0	27194.0
Total Domestic Consumption	14376.0	14775.0	15083.0	15455.0	15805.0	16154.0	17158.0	19186.0	20310.0	21242.0
Interprovincial Transfers (Net)	1038.0	1342.0	850.0	850.0	850.0	850.0	850.0	850.0	850.0	850.0
Exports (Net)	5387.0	5993.0	4785.0	4413.0	4063.0	3714.0	2710.0	7152.0	6034.0	5102.0
					Saskatchewan (Gigawatt hours)					
Coal Fired Steam										
–Bituminous										
–Sub-Bituminous	48.0	50.0	650.0	650.0	600.0	600.0	500.0	350.0	200.0	50.0
–Lignite	6610.0	7249.0	7401.0	7849.0	7192.0	7552.0	8743.0	10884.0	13115.0	12868.0

Table A5-5 (Cont'd)

Type of Generation	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Saskatchewan (Cont'd)					
Oil Fired Steam										
–Light	20.0									
–Heavy	2.0	14.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Natural Gas Fired Steam	222.0	158.0	163.0	170.0	163.0	182.0	210.0	278.0	318.0	321.0
Gas Turbines										
–Light Oil										
–Diesel Oil										
–Natural Gas	61.0	36.0								
Internal Combustion										
–Diesel Oil	14.0	29.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Nuclear										
Hydroelectric	2360.0	2264.0	2762.0	2762.0	3832.0	3832.0	3832.0	3837.0	3837.0	6167.0
Other	115.0	146.0	146.0	169.0	177.0	185.0	196.0	229.0	282.0	282.0
Total Energy Generation	9452.0	9946.0	11155.0	11633.0	11997.0	12384.0	13514.0	15611.0	17785.0	19721.0
Total Domestic Consumption	9842.0	10352.0	11629.0	12107.0	12471.0	12858.0	13988.0	16085.0	18259.0	20195.0
Interprovincial Transfers (Net)	–450.0	–487.0	–474.0	–474.0	–474.0	–474.0	–474.0	–474.0	–474.0	–474.0
Exports (Net)	60.0	81.0								
					Alberta (Gigawatt hours)					
Coal Fired Steam										
–Bituminous	497.0	527.0								
–Sub-Bituminous	19901.0	20264.0	24396.0	24982.0	29006.0	31195.0	36179.0	36175.0	37100.0	46071.0
–Lignite										
Oil Fired Steam										
–Light	5.0	16.0								
–Heavy	58.0	19.0	19.0	27.0	27.0	27.0	10.0	10.0	10.0	10.0
Natural Gas Fired Steam	3026.0	4150.0	922.0	1441.0	3099.0	2451.0	2001.0	1789.0	1186.0	1032.0
Gas Turbines										
–Light Oil										
–Diesel Oil										
–Natural Gas	1432.0	1595.0	1072.0	1072.0	1072.0	1072.0	1072.0	1072.0	1072.0	1072.0
Internal Combustion										
–Diesel Oil	64.0	67.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
Nuclear										
Hydroelectric	1590.0	1480.0	1636.0	1636.0	1636.0	1636.0	1636.0	5386.0	14386.0	14386.0
Other	520.0	639.0	639.0	652.0	664.0	677.0	723.0	757.0	840.0	840.0

Table A5-5 (Cont'd)

Type of Generation	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Alberta (Cont'd)					
Total Energy Generation	27093.0	28757.0	28720.0	29846.0	35540.0	37094.0	41657.0	45225.0	54630.0	63447.0
Total Domestic Consumption	27352.0	28899.0	28820.0	29946.0	31340.0	32594.0	36457.0	43225.0	51130.0	59147.0
Interprovincial Transfers (Net)	–259.0	–142.0	–100.0	–100.0	–100.0	–100.0	–100.0	–100.0	–100.0	–100.0
Exports (Net)					4300.0	4600.0	5300.0	2100.0	3600.0	4400.0
					British Columbia (Gigawatt hours)					
Coal Fired Steam										
–Bituminous										
–Sub-Bituminous										
–Lignite										
Oil Fired Steam										
–Light	130.0									
–Heavy	513.0	340.0	340.0	308.0	320.0	335.0	341.0	195.0	227.0	227.0
Natural Gas Fired Steam	234.0	516.0	338.0	252.0	262.0	274.0	341.0	545.0	591.0	591.0
Gas Turbines										
–Light Oil			196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0
–Diesel Oil										
–Natural Gas										
Internal Combustion										
–Diesel Oil	256.0	246.0	124.0	124.0	124.0	124.0	124.0	94.0	94.0	94.0
Nuclear										
Hydroelectric	47100.0	47436.0	58287.0	61204.0	61154.0	61154.0	61964.0	66072.0	78423.0	89301.0
Other	1103.0	777.0	777.0	838.0	873.0	913.0	1022.0	1130.0	1274.0	1274.0
Total Energy Generation	49336.0	49315.0	60062.0	62922.0	62929.0	62996.0	63988.0	68232.0	80805.0	91683.0
Total Domestic Consumption	44894.0	46600.0	46559.0	48526.0	50128.0	51301.0	55318.0	64852.0	76674.0	88203.0
Interprovincial Transfers (Net)	259.0	142.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Exports (Net)	4183.0	2573.0	13403.0	14296.0	12701.0	11595.0	8570.0	3280.0	4031.0	3380.0

Table A5-5 (Cont'd)

Type of Generation	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Yukon (Gigawatt hours)					
Coal Fired Steam										
–Bituminous										
–Sub-Bituminous										
–Lignite										
Oil Fired Steam										
–Light										
–Heavy										
Natural Gas Fired Steam										
Gas Turbines										
–Light Oil										
–Diesel Oil	72.0	22.0	39.0	57.0	72.0	83.0	120.0	208.0	166.0	122.0
–Natural Gas										
Internal Combustion										
–Diesel Oil										
Nuclear										
Hydroelectric	272.0	221.0	288.0	388.0	388.0	388.0	388.0	388.0	538.0	688.0
Other										
Total Energy Generation	344.0	243.0	327.0	395.0	460.0	471.0	508.0	596.0	704.0	810.0
Total Domestic Consumption	344.0	243.0	327.0	395.0	460.0	471.0	508.0	596.0	704.0	810.0
Interprovincial Transfers (Net)										
Exports (Net)										
					Northwest Territories (Gigawatt hours)					
Coal Fired Steam										
–Bituminous										
–Sub-Bituminous										
–Lignite										
Oil Fired Steam										
–Light										
–Heavy										
Natural Gas Fired Steam										

Table A5-5 (Cont'd)

Type of Generation	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
				Northwest Territories (Cont'd)						
Gas Turbines										
–Light Oil										
–Diesel Oil										
–Natural Gas										
Internal Combustion										
–Diesel Oil	222.0	215.0	256.0	279.0	298.0	311.0	296.0	402.0	536.0	561.0
Nuclear										
Hydroelectric	275.0	279.0	265.0	265.0	265.0	265.0	325.0	325.0	325.0	429.0
Other										
Total Energy Generation	497.0	494.0	521.0	544.0	563.0	576.0	621.0	727.0	861.0	990.0
Total Domestic Consumption	497.0	494.0	521.0	544.0	563.0	576.0	621.0	727.0	861.0	990.0
Interprovincial Transfers (Net)										
Exports (Net)										

Table A5-6
Demand for Fuel Sources for Generation of Electricity – Canada
NEB Projection

(Petajoules)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Coal										
– Bituminous	394.6	391.8	450.4	321.0	329.3	331.2	327.2	393.8	420.0	462.0
– Sub-Bituminous	218.7	247.4	276.2	282.6	326.1	350.1	403.3	401.3	409.7	506.0
– Lignite	107.0	104.5	117.8	121.8	110.7	113.6	129.8	159.1	189.4	186.1
– Total Coal	720.3	743.7	844.4	725.4	766.1	794.9	860.3	954.2	1019.1	1154.1
Oil										
– Light	4.9	2.3	13.9	14.3	14.9	14.9	14.9	21.7	28.6	29.8
– Heavy	87.7	42.0	67.2	82.0	57.7	80.5	89.0	6.5	11.5	6.3
– Diesel	12.7	10.8	7.5	8.2	8.6	8.9	9.2	11.6	13.0	12.9
– Total Oil	105.3	55.1	88.6	104.5	81.2	104.3	113.1	39.8	53.1	49.0
Natural Gas	61.8	64.3	27.9	33.9	53.5	46.1	42.2	41.4	34.5	32.7
Uranuim	381.4	466.6	519.8	723.2	761.3	817.2	997.0	1207.6	1431.5	1603.0
Hydroelectric	2716.1	2828.0	3027.8	3125.5	3227.4	3279.1	3288.3	3741.1	4235.9	4580.4
Other	24.0	22.8	22.8	24.1	25.5	27.5	31.3	35.2	40.7	40.7
Total Energy Generation	4008.9	4180.5	4531.3	4736.6	4915.0	5069.1	5332.2	6019.3	6814.8	7459.9

Table A5-7
(Net) Electricity Exports
NEB Projection

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					(Gigawatt hours)					
Province or Territory										
New Brunswick	2940	5685	5205	5395	5558	6297	6273	8888	6421	6045
Quebec	8536	10227	18212	18501	20169	20856	10744	9840	5365	
Ontario	10649	11838	11949	12773	13273	13773	11993	6791	8922	5078
Manitoba	5387	5993	4785	4413	4063	3714	2710	7152	6034	5102
Saskatchewan	60	81								
Alberta					4300	4600	5300	2100	3600	4400
British Columbia	4183	2573	13403	14296	12801	11595	8570	3280	4031	3380
Canada	**31755**	**36397**	**53554**	**55378**	**60164**	**60835**	**45590**	**38051**	**34373**	**24005**
					(Petajoules)[1]					
Province or Territory										
New Brunswick	30.3	56.0	61.8	57.4	59.1	67.0	66.7	94.6	68.3	62.9
Quebec	84.8	101.4	192.1	195.2	213.0	220.0	113.3	103.8	56.5	
Ontario	95.7	107.1	112.6	121.2	125.2	129.9	113.1	64.7	85.9	49.8
Manitoba	56.8	64.6	50.5	46.6	42.9	39.2	28.6	79.7	63.7	53.9
Saskatchewan	.5	.8								
Alberta					47.2	50.4	58.0	23.0	39.5	48.2
British Columbia	44.0	27.2	141.5	147.5	131.7	118.9	87.1	31.1	39.0	35.6
Canada	**312.1**	**357.1**	**558.5**	**567.9**	**619.1**	**625.4**	**466.8**	**396.9**	**352.9**	**250.4**

[1] Converted from gigawatt hours using plant specific factors for fossil fuels and 10.5 megajoules per kilowatt hour for hydro and nuclear.

Table A5-8
Electricity Exports by Fuel Type
NEB Projection

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					(Gigawatt hours)					
Type of Fuel										
Hydro	17500.0	18425.0	37816.0	37702.0	37525.0	36655.0	22516.0	20764.0	15430.0	8612.0
Coal	13742.0	15979.0	12408.0	14346.0	19409.0	21348.0	20112.0	10409.0	12956.0	9250.0
Nuclear		1493.0	2830.0	2830.0	2830.0	2830.0	2962.0	6878.0	5987.0	6143.0
Oil	513.0	500.0	500.0	500.0	400.0					
Total	31755.0	36397.0	53554.0	55378.0	60164.0	60835.0	45590.0	38051.0	34373.0	24005.0

Table A6-1
Historical Data
Established Reserves and Cumulative Production of Marketable Natural Gas From Conventional Producing Areas

(Exajoules)

Year	Initial Established Reserves	Cumulative Production	Remaining Established Reserves
1960	38.43	4.94	33.49
1961	42.46	5.80	36.66
1962	45.57	6.83	38.74
1963	48.33	7.93	40.40
1964	50.00	9.15	40.85
1965	58.49	7.94	50.55
1966	59.84	9.19	50.65
1967	64.80	10.61	54.19
1968	67.85	12.03	55.82
1969	74.77	13.93	60.84
1970	77.10	15.73	61.37
1971	82.86	18.25	64.61
1972	83.20	20.77	62.43
1973	87.42	23.48	63.94
1974	89.20	26.17	63.03
1975	91.07	28.88	62.19
1976	96.29	31.42	64.87
1977	102.70	34.25	68.45
1978	110.94	36.89	74.05
1979	115.94	40.00	75.94
1980	119.16	42.77	76.39
1981	126.52	45.74	80.78
1982	129.97	48.52	81.45
1983(1)	132.27	51.32	80.95

Source CPA Data – 1960-1964 (probable reserves category)
NEB Data – 1965-1982 (NEB data non-existent prior to 1965)

(1) Estimate

Table A6-2
Natural Gas Reserves Additions Per Unit of Exploratory Drilling
And Initial Established Reserves
Conventional Producing Areas

Historical			Projection		
Year	Exajoules per Million Metres	Initial Established Reserves	Year	Exajoules per Million Metres	Initial Established Reserves
1960-61	3.10	38.4	1983	1.06	132.3
1962-63	3.02	45.6	1984	1.01	134.2
1964-65	3.51	50.0	1985	0.99	136.5
1966-67	2.19	59.8	1986	0.96	138.8
1968-69	2.73	67.9	1987	0.95	141.2
1970-71	2.43	77.1	1990	0.86	148.1
1972-73	1.29	83.2			
1974-75	1.18	89.2	1995	0.64	157.0
1976-77	2.57	96.3			
1978-79	1.90	110.9	2000	0.51	162.1
1980-81	1.25	119.2			
1982-83	1.11	130.0	2005	0.37	164.1

Table A6-3
Exploratory Drilling Activity
Historical Data and NEB Projection

(Million Metres)

Historical		Projection	
Year	Total	Year	Total
1960	1.19	1983	2.15
1961	1.28	1984	2.45
1962	1.24	1985	2.68
1963	1.63	1986	2.87
1964	1.85	1987	3.10
1965	2.08		
		1990	3.53
1966	2.05		
1967	1.91	1995	3.11
1968	2.23		
1969	2.21	2000	2.14
1970	1.82		
		2005	1.38
1971	1.76		
1972	2.05		
1973	2.25		
1974	1.87		
1975	1.66		
1976	2.28		
1977	2.78		
1978	3.56		
1979	4.11		
1980	5.27		
1981	4.25		
1982	3.12		

Table A6-4
Exploratory Drilling Activity By Province
NEB Projection

(Million Metres)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
Alberta	1.65	1.93	2.11	2.29	2.61	3.09	2.67	1.91	1.19
British Columbia	0.08	0.10	0.15	0.18	0.22	0.26	0.26	0.14	0.10
Saskatchewan	0.38	0.38	0.38	0.37	0.25	0.17	0.17	0.08	0.08
Manitoba	0.04	0.04	0.04	0.03	0.02	0.01	0.01	0.01	0.01
Total	2.15	2.45	2.68	2.87	3.10	3.53	3.11	2.14	1.38

Table A6-5
Marketable Natural Gas Reserves Additions Historical Data and NEB Projection

(Exajoules)

	Historical			Projection	
Year	Annual Additions	3 Year Rolling Average		Year	Annual Additions
1960	5.00	3.72		1983	2.28
1961	2.00	3.77		1984	2.48
1962	4.30	3.03		1985	2.65
1963	2.80	3.97		1986	2.75
1964	4.80	4.13		1987	2.94
1965	4.80	3.65		1990	3.05
1966	1.34	3.70		1995	1.99
1967	4.96	3.12		2000	1.09
1968	3.04	4.98		2005	0.51
1969	6.92	4.10			
1970	2.34	5.01			
1971	5.76	2.81			
1972	0.34	3.44			
1973	4.22	2.11			
1974	1.78	2.62			
1975	1.87	2.96			
1976	5.22	4.50			
1977	6.41	6.62			
1978	8.23	6.55			
1979	5.00	5.49			
1980	3.22	5.20			
1981	7.36	4.68			
1982	3.45	4.36			

Table A6-6
Marketable Natural Gas Reserves Additions From Appreciation and New Discoveries Conventional Areas NEB Projection

(Petajoules)

1983	1984	1985	1986	1987	1990	1995	2000	2005	Total (1983-2005)
2280	2480	2650	2750	2940	3050	1990	1090	510	45460

Table A6-7
Marketable Natural Gas Reserves Additions
Conventional Areas
Comparison of Submittors' Views

(Petajoules)

	Amoco Base	Amoco Expanded	CPA	Dome	Imperial	Husky/ NOVA	Petro-Canada	Shell[1]	TCPL[1]	NEB
1983	3993	5972	3718	3201	3740	3830	2625	2298	1720	2280
1984	3993	5972	3682	2997	3780	3420	2200	2475	1750	2480
1985	3954	5933	3682	3464	3750	3080	2825	2509	2200	2650
1986	3721	5700	3644	3650	3860	2766	3150	2488	2690	2750
1987	3488	5467	3372	3865	3900	2556	3460	2377	3130	2940
1988	3294	5273	3139	4157	3890	2382	3770	2245	3530	3200
1989	3100	5079	3139	4196	4030	2292	4330	2177	3410	3190
1990	2402	4381	2906	4050	4140	2252	4155	2071	3290	3050
1991	2247	4226	2364	3850	3940	2288	3880	2093	3200	2880
1992	2053	3876	2053	3734	2720	2348	3680	2039	3110	2690
1993	2053	3876	2053	3564	2570	2398	3430	1976	2720	2500
1994	1859	3527	1859	3447	2390	2435	3170	1881	2410	2250
1995	1859	3527	1859	3277	2210	2445	2870	1766	2110	1990
			37470[2]							
1996	1665	3217		3161	2000	2445	2685	1664	1870	1800
1997	1665	3217		2885	1780	2471	2433	1681	1660	1610
1998	1471	2945		2715	1590	2461	2300	1592	1470	1430
1999	1471	2945		2705	1410	2467	2075	1471	1310	1240
2000	1277	2674		2686	1250	2487	1968	1332	1170	1090
	45565[2]	77807[2]			52950[2]			36135[2]		
2001				2686		2487	1786		1040	920
2002				2623		2483	1606		930	790
2003				2623		2483	1543		830	640
2004				2596		2483	1392		750	580
2005				2596		2479	1355		670	510
Total				74728		59238	62688		46970	45460

[1] Alberta & British Columbia only.
[2] Mid-forecast total

Table A6-8
Deliverability from Established Reserves
Comparison of Submittors' Views

(Petajoules Per Year)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
Amoco	4872	5210	5198	5026	4984	4219	2747	1615	949
CPA	4701	4771	4786	4617	4573	3823	2549	—	—
Dome	5112	5382	5651	5704	5564	4839	3274	2113	1259
Gulf	4349	4389	4349	4270	4149	3671	2753	1756	—
Imperial	4733	4620	4562	4448	4351	3725	2503	1431	—
NOVA	5168	5126	5023	4858	4648	4360	2991	1794	1162
Petro-Canada	5111	4977	4929	4763	4610	3895	2543	1603	979
Shell[1]	—	5198	5082	4971	4823	3781	2136	1233	—
TCPL	4897	5106	4917	4784	4623	3884	2519	1530	972
Texaco[1]	5040	5198	5082	4971	4823	3781	2136	1233	—
NEB	5022	5050	5060	4906	4781	4116	2651	1442	859

(1) Adopted NEB '82 Omnibus.

Table A6-9
Deliverability from Conventional Producing Areas
Established Reserves and Reserves Additions
Comparison of Submittors' Views

(Petajoules Per Year)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
Amoco-Base	4985	5422	5509	5436	5621	5450	4517	3527	2754
Amoco-Expanded	4985	5422	5509	5550	5862	6060	5720	4943	4272
CPA	4701	4856	4956	4871	4913	4757	4205	—	—
Dome	5112	5400	5714	5856	5859	5732	5218	4650	3949
Gulf	4349	4389	4389	4349	4309	4149	3950	3750	—
Imperial	4965	5015	5097	5183	5305	5399	4983	3918	—
NOVA	5169	5128	5026	4866	4670	4567	3890	3309	3103
Petro-Canada	5125	5020	5030	4956	4919	4662	4209	3809	3237
Shell[1]	—	5422	5383	5358	5280	4482	3188	2558	—
TCPL	4919	5162	5026	4972	4911	4582	3939	3260	2606
Texaco[2]	5102	5338	5347	5387	5399	4827	3698	2905	—
NEB	5034	5994	5161	5100	5091	4844	4054	3122	2422

(1) Adopted NEB '82 Omnibus for Established Reserves Portion.
(2) Adopted NEB '82 Omnibus.

Table A6-10
Deliverability from Frontier Regions Comparison of Submittors' Views

(Petajoules Per Year)

	1989	1990	1991	1992	1993	1994	1995	2000	2005
Dome	150	150	150	150	150	150	390	1220	2290
Gulf	150	150	150	150	150	150	150	650	—
Imperial	—	—	—	149	149	149	298	608	—
Mobil[1]	90	115	140	140	140	140	140	—	—
NOVA	—	80	150	150	150	150	250	650	900
Petro-Canada[2]	114	140	146	146	146	146	239	240	181
Shell[3]	485	485	485	485	485	485	485	485	—
NEB	—	—	—	—	—	140	460	460	460

(1) Venture only, commencing mid-1988.
(2) Commencing 1988 at 44 PJ.
(3) Total East Coast commencing 1987.

Table A6-11
Deliverability From Conventional Areas
NEB Projection

(Petajoules Per Year)

	British Columbia Supply				Alberta Supply				Sask, Ont + Terr Supply				Total Conventional Supply			
Year	Contr. Res.	Uncom. Res.	Res. Addns.	Total	Contr. Res.	Uncom. Res.	Res. Addns.	Total	Contr. Res.	Uncom. Res.	Res. Addns.	Total	Contr. Res.	Uncom. Res.	Res. Addns.	Total
1983	466	33	1	500	4378	54	11	4443	85	7	0	92	4928	94	12	5034
1984	467	43	3	512	4329	107	39	4475	90	15	2	107	4886	164	44	5094
1985	461	56	7	524	4268	160	91	4519	92	22	4	118	4822	238	102	5161
1986	436	94	14	544	3992	264	173	4429	91	29	7	127	4519	387	194	5100
1987	425	107	25	556	3756	368	276	4400	89	36	10	136	4270	511	311	5091
1988	417	115	38	569	3449	520	389	4358	86	40	14	140	3952	674	441	5067
1989	412	120	53	585	2990	668	509	4167	82	39	18	139	3484	826	581	4891
1990	389	124	71	584	2673	814	636	4123	79	37	21	137	3141	974	728	4844
1991	355	125	89	569	2417	901	766	4084	73	34	24	132	2845	1060	879	4784
1992	314	128	106	548	2121	929	894	3943	65	30	27	122	2499	1088	1027	4613
1993	285	130	123	538	1820	937	1014	3770	55	26	29	110	2160	1093	1166	4418
1994	253	128	139	520	1556	923	1122	3600	51	23	31	105	1860	1073	1292	4225
1995	227	124	154	505	1353	880	1216	3449	48	20	32	100	1627	1024	1403	4054
1996	194	123	167	484	1147	832	1294	3273	45	17	34	95	1385	972	1496	3852
1997	170	120	179	468	952	782	1356	3090	42	14	35	91	1164	916	1569	3649
1998	149	118	188	455	771	729	1400	2899	39	11	36	86	959	857	1624	3441
1999	121	115	195	432	656	674	1428	2758	34	9	37	80	812	798	1661	3270
2000	106	110	200	416	567	625	1442	2634	27	7	37	72	701	741	1680	3122
2001	91	102	203	395	487	578	1443	2507	26	5	37	69	604	684	1683	2971
2002	81	92	202	375	423	536	1432	2391	24	4	37	65	528	632	1671	2831
2003	72	83	200	354	357	497	1410	2264	23	3	35	62	451	583	1646	2680
2004	66	73	196	335	316	463	1379	2158	22	3	34	58	403	538	1609	2551
2005	61	64	191	316	279	432	1340	2051	21	2	32	55	361	498	1563	2422
Total	6017	2322	2746	11085	45054	13670	21061	79785	1290	433	574	2297	52361	16425	24380	93167

Figures may not add due to rounding.

Table A6-12
Deliverability From All Sources
NEB Projection

(Petajoules Per Year)

	Deliverability from Established Reserves								Supply from Reserves Additions					Frontier Supply		
Year	Total Control	S.E. Alta Uncom	Other Alta Uncom	B.C. Uncom	Sask Uncom	Alta Ber	Alta Defer	Total	Alta	B.C.	Sask	Total	Western Canada	Total Scotian Shelf	Mackenzie Delta	Total Canadian Including Frontiers
1982[1]	56811	3390	12378	2930	442	1760	3741	81452	39270	5388	800	45458				
1983	4928	19	32	33	7	2	1	5022	11	1	0	12	5034	0	0	5034
1984	4886	38	65	43	15	4	1	5050	39	3	2	44	5094	0	0	5094
1985	4822	56	97	56	22	6	1	5060	91	7	4	102	5161	0	0	5161
1986	4519	94	161	94	29	7	2	4906	173	14	7	194	5100	0	0	5100
1987	4270	130	226	107	36	9	3	4781	276	25	10	311	5091	0	0	5091
1988	3952	183	323	115	40	11	3	4626	389	38	14	441	5067	0	0	5067
1989	3484	231	420	120	39	13	4	4310	509	53	18	581	4891	0	0	4891
1990	3141	276	517	124	37	15	6	4116	636	71	21	728	4844	140	0	4984
1991	2845	299	579	125	34	16	7	3905	766	89	24	879	4784	140	0	4924
1992	2499	296	606	128	30	18	9	3586	894	106	27	1027	4613	140	0	4753
1993	2160	281	618	130	26	19	18	3252	1014	123	29	1166	4418	140	0	4558
1994	1860	256	619	128	23	21	27	2933	1122	139	31	1292	4225	140	0	4365
1995	1627	221	602	124	20	22	35	2651	1216	154	32	1403	4054	140	320	4514
1996	1385	186	579	123	17	23	43	2357	1294	167	34	1496	3852	140	320	4312
1997	1164	156	550	120	14	24	52	2080	1356	179	35	1569	3649	140	320	4109
1998	959	130	516	118	11	25	58	1817	1400	188	36	1624	3441	140	320	3901
1999	812	108	479	115	9	26	62	1609	1428	195	37	1661	3270	140	320	3730
2000	701	88	442	110	7	27	68	1442	1442	200	37	1680	3122	140	320	3582
2001	604	72	407	102	5	27	72	1288	1443	203	37	1683	2971	140	320	3431
2002	528	58	373	92	4	28	77	1160	1432	202	37	1671	2831	140	320	3291
2003	451	45	343	83	3	28	81	1034	1410	200	35	1646	2680	140	320	3140
2004	403	34	314	73	3	29	85	942	1379	196	34	1609	2551	140	320	3011
2005	361	26	289	64	2	30	88	859	1340	191	32	1563	2422	140	320	2882
Total	**52361**	**3282**	**9156**	**2322**	**433**	**428**	**803**	**68786**	**21061**	**2746**	**574**	**24380**	**93167**	**2240**	**3520**	**98927**

[1] Remaining Reserves at 31 December, 1982.

Figures may not add due to rounding.

Table A6-13
Connection Rates for Gas Reserves
NEB Projection

(Percent)

Year After Addition	Uncommitted Alberta Reserves	Uncommitted Saskatchewan Reserves	Reserves Additions
0	5	15	10
1	5	15	15
2	5	15	20
3	10	15	25
4	10	15	15
5	15	10	5
6	15	5	2
7	15	3	2
8	10	3	2
9	5	2	1
10	3	1	1
11	2	1	1
12			1
13			1

Table A6-14
Natural Gas Exports by Licence(1),(2)
NEB Projection

(Petajoules)(3)

Company	Licence	Delivery Point	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	Total
A&S	GL-3	Kingsgate	163.5	115.9	130.6	110.2	30.7											550.9
	GL-16	"	5.3	7.6	8.2	57.3	59.9	63.8	67.8									269.9
	GL-24	"	30.2	38.0	44.0	59.7	62.3	66.5	70.6	76.8	74.8	53.5	42.8					619.2
	GL-35	"	72.0	57.7	56.1	51.7	54.0											291.5
	GL-67	"					91.9	130.8	138.9	147.1	98.0	49.0						655.7
	GL-68	"								71.8	47.8	23.9						143.5
	GL-69	"						57.6	61.2	64.8	43.1	21.6						248.3
Pan-Alberta	GL-59	"	43.1	37.5	37.4	23.4	14.1	65.6										221.1
	GL-63	"				23.4	42.2											65.6
	GL-65	"							74.9	84.3	56.2	28.1						243.5
Westcoast	GL-4	"	29.9	51.1	40.8	27.2	13.6											162.6
	GL-41	"		8.7	16.8	23.1	31.1	33.6	35.7									149.0
	GL-94	"								34.6	34.5	35.1						104.2
Total		**Kingsgate**	**344.0**	**316.5**	**333.9**	**376.0**	**399.8**	**417.9**	**449.1**	**479.4**	**354.4**	**211.2**	**42.8**					**3725.0**
Canadian-Montana	GL-5	Niagara Falls					2.2											2.2
	GL-17	"					5.8	6.2	6.6									18.6
	GL-25	"					5.8	6.2	6.6	7.0	7.0	4.5	4.0					41.1
	GL-53	"					1.5											1.5
	GL-70	"					5.5	4.7	5.0	5.3	3.5	1.7						25.7
	GL-71	"								3.5	2.3	1.2						7.0
KannGaz	GL-77	"					36.5	38.9	41.4	43.8	43.8	43.8	43.8	32.8	21.9	10.9		357.6
Pan-Alberta	GL-95	"					44.7	47.6	50.6	53.6	53.6	53.6	53.6	40.2	26.8	13.4		437.7
ProGas	GL-80	"					14.6	15.6	16.6	17.6	17.6	17.6	17.6	13.2	8.8	4.4		143.6
Sulpetro	GL-57	"	17.9	6.4														24.3
	GL-82	"		12.1	21.9	23.4	24.8	24.8	23.9	10.5	5.3							146.7
TransCanada	GL-83	"			36.1	36.1	32.5	32.5	32.5	32.5	32.5	32.5	32.5	24.4				324.1
	GL-84	"					14.6	15.6	16.6	17.6	17.6	17.6	17.6	13.2				130.4
	GL-85	"					54.3	57.9	61.6	65.2	65.2	65.2	48.9	32.6	16.3			467.2
	GL-88	"					22.0	23.4	24.9	26.3	26.3	26.3	26.3	19.8	13.2	6.6		215.1
	GL-90	"					14.6	15.6	16.6	17.6	17.6	17.6	17.6	17.6	13.2	8.8	4.4	161.2
Total		**Niagara Falls**	**17.9**	**18.5**	**58.0**	**59.5**	**279.4**	**289.0**	**302.9**	**300.5**	**292.3**	**281.6**	**261.9**	**193.8**	**100.2**	**44.1**	**4.4**	**2504.0**

Table A6-14 (Cont'd)

Company	Licence	Delivery Point	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	Total.
Consolidated	GL-61	Emerson	26.5	16.7	11.7	8.9	12.2											76.0
	GL-75	"						21.0	22.3									43 3
TransCanada	GL-18	"	13.8	7.4		33.5	39.0	41.8	44.6									180.1
	GL-20	"	11.0	17.7	18.6	19.3	19.8	24.0	27.4	30.8	30.8							199.4
	GL-37	"	32.1	44.2	39.4	51.5	64.0	53.5	61.1	68.8								414.6
	GL-38	"	3.5	9.8	19.5	19.5	19.5	19.5	19.5	19.5								130.3
	GL-39	"	.7			1.7	2.0	2.1	2.2	2.5								11.2
	GL-60	"	19.5	61.4	57.5	3.1												141.5
	GL-86	"				19.5	35.1	35.1	35.1	35.1	35.1	35.1	35.1	26.3	17.6	8.8		317.9
	GL-87	"							33.2	35.1	35.1	35.1	35.1	26.3	17.6	8.8		226.3
	GL-88	"					22.0	23.4	24.9	26.3	26.3	26.3	26.3	19.8	13.2	6.6		215 1
	GL-89	"			11.3	44.2	55.2	59.2	63.1	71.0	47.3	23.7						375.0
ProGas	GL-56	"	46.7	24.6	21.0													92.3
	GL-79	"						21.0	10.5									31.5
	GL-81	"			54.3	43.5	54.3	57.9	61.6	65.2	65.2	65.2	48.9	32.6	16.3			565.0
Total		**Emerson**	**153.8**	**181.8**	**233.3**	**244.7**	**323.1**	**358.5**	**405.5**	**354.3**	**239.8**	**185.4**	**145.4**	**105.0**	**64.7**	**24.2**		**3019.5**
Canadian-Montana	GL-5	Cardston																
	GL-17	"																
	GL-25	"																
	GL-36	"	1.9															1.9
	GL-53	"																
	GL-52	Aden		7.0	7.0	6.9	6.9	1.2										29.0
	GL-72	"						6.0	8.2	9.2	6.1	3.1						32.6
Total		**Cardston/Aden**	**1.9**	**7.0**	**7.0**	**6.9**	**6.9**	**7.2**	**8.2**	**9.2**	**6.1**	**3.1**						**63.5**
Columbia	GL-54	Monchy				9.7	11.1	2.3										23.1
	GL-74	"						11.4	15.6	17.5	11.7	5.8						62.0
Consolidated	GL-61	"		22.2	27.2	37.8	27.2											114.4
	GL-75	"						21.0	22.3									43.3
Pan-Alberta	GL-58	"	124.9	124.9	140.5	78.1	149.1	218.6										836.1
	GL-62	"				78.1	38.3											116.4
	GL-66	"							249.8	281.1	187.2	93.6						811.7
ProGas	GL-56	"		32.6	66.5	70.0	63.0											232 1
	GL-79	"						21.0	10.5									31.5
Westcoast	GL-41	"		4.0	7.8	10.7	14.4	15.5	16.5									68.9
	GL-94	"								17.3	17.8	17.3						52.4
Total		**Monchy**	**124.9**	**183.7**	**242.0**	**284.4**	**303.1**	**289.8**	**314.7**	**315.9**	**216.7**	**116.7**						**2391.9**
ICG	GL-28	Sprague	.4	.2	.3	.3	.3	3	.3	.3	.3	3	.3	3	.3			3.9
	GL-29	Fort-Frances	5.2	4.1	5 7	6.1	6.5	7.0	7.4	7.4	7.4	7.4	7.4	7.4	·7.4			86.4
Total		**ICG**	**5.6**	**4.3**	**6.0**	**6.4**	**6.8**	**7.3**	**7.7**	**7.7**	**7.7**	**7.7**	**7.7**	**7.7**	**7.7**			**90.3**

Table A6-14 (Cont'd)

Company	Licence	Delivery Point	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	Total.
Niagara Gas	GL-6	Cornwall	.8															.8
	GL-55	"	4.6	7.2	7.5	8.5	8.8											36.6
	GL-78	"						8.8	8.8	9.3	6.2	3.1						36.2
Total		**Cornwall**	**5.4**	**7.2**	**7.5**	**8.5**	**8.8**	**8.8**	**8.8**	**9.3**	**6.2**	**3.1**						**73.6**
Westcoast	GL-41	Huntingdon	92.7	56.2	102.2	140.5	189.1	204.4	217.2									1002.3
	GL-93	"								109.2	109.2	109.2	81.9	54.6	27.3			491.4
	GL-94	"								109.3	54.3							163.6
Total		**Huntingdon**	**92.7**	**56.2**	**102.2**	**140.5**	**189.1**	**204.4**	**217.2**	**218.5**	**163.5**	**109.2**	**81.9**	**54.6**	**27.3**			**1657.3**
TransCanada	GL-19	Philipsburg	4.8	6.2	6.2	6.2	6.2	6.2	6.2									42.0
Dome	GL-76	Grassy Point						66.6	124.1	148.7	156.6	165.0	166.6	166.6	166.6	166.6	166.6[4]	1993
Total All Licences			**751.0**	**781.4**	**996.1**	**1133.1**	**1523.2**	**1655.7**	**1844.8**	**1843.5**	**1443.3**	**1083.0**	**706.3**	**527.7**	**366.5**	**234.9**	**171.0**	**15561.3**

(1) Licence years November-October.
(2) Allowance excludes GL-43 fuel licence and Union Gas Licences GL-64 and GL-92 for SNG export.
(3) Gas Heating Value (MJ/m^3) – Huntingdon @ 39.10, Grassy Point @ 38.20, Aden @ 36.06 and all other delivery point @ 37.65.
(4) Dome GL-76 continues for licence years through to 2000/2001.

Table A6-15
Short Term Natural Gas Exports
Comparison of Submittors' Views

(Billions of Cubic Metres)

Companies	**1983**	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**
Shell	23.0	24.6	27.2	29.4	30.5	32.0	30.6	30.8
Husky/NOVA	20.4	21.2	21.2	22.8	24.2	—	—	29.5
APMC	20.8	22.1	25.0	28.2	35.6	—	—	42.8
Dome – Low	21.4	24.2	26.9	29.5	32.2	—	—	43.0
– High	21.5	26.9	32.2	37.6	45.7	—	—	59.1
Gulf	19.0	19.1	22.6	31.1	39.6	—	—	52.2
Amoco	22.7	22.7	28.3	31.2	34.0	39.7	45.3	51.0
EUPC	21.5	22.8	28.2	37.6	43.6	45.7	45.7	45.7
NEB-Forecast	20.2	20.7	25.7	29.9	40.2	44.0	49.0	48.5
-Authorized	47.1	49.3	58.1	59.0	59.7	59.2	58.7	53.9

Table A6-16
Natural Gas Exports — History and NEB Projection

(Billions of Cubic Metres)

Historical			Projection		
Year	Authorized	Actuals[1]	Year	Authorized	Exports
1960/61	—	4.8	1983/84	49.3	20.7
1961/62	—	9.7	1984/85	58.1	25.7
1962/63	—	10.2			
1963/64	—	11.1	1985/86	59.0	29.9
1964/65	—	11.5	1986/87	59.9	40.2
			1987/88	59.2	44.0
1965/66	—	12.2	1988/89	58.7	49.0
1966/67	—	14.5	1989/90	53.9	48.5
1967/68	—	17.1			
1968/69	—	19.3	1990/91	42.0	38.0
1969/70	—	22.1	1991/92	30.5	27.9
			1992/93	19.8	18.3
1970/71	24.9	25.8	1993/94	15.0	13.9
1971/72	30.4	28.4	1994/95	10.3	9.7
1972/73	29.6	29.2			
1973/74	29.5	27.3	1995/96	6.7	6.4
1974/75	29.0	27.0	1996/97	4.5	4.5
			1997/98	4.4	4.4
1975/76	29.0	27.1	1998/99	4.4	4.4
1976/77	30.2	28.0	1999/00	4.4	4.4
1977/78	29.0	25.2			
1978/79	29.3	27.6	2000/01	1.8	1.8
1979/80	30.8	23.4	2001/02	—	—
			2002/03	—	—
1980/81	40.6	22.0	2003/04	—	—
1981/82	46.6	21.9	2004/05	—	—
1982/83	47.1	20.2			

[1] 1960 – 1983 Actual
1984 – 2005 Forecast

Table A6-17
Historical Data – Primary Demand for Natural Gas – Canada

(Petajoules)

	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970
Residential	N/A	N/A	150.9	161.6	178.6	201.5	208.0	215.2	227.1	244.1	255.1
Commercial	N/A	N/A	75.7	78.8	94.1	111.3	126.2	140.0	159.1	191.7	203.3
Petrochemical	N/A	N/A	32.6	36.7	40.4	44.4	52.5	56.1	60.0	70.7	86.9
Other Industrial	N/A	N/A	151.9	166.9	186.0	188.2	213.8	241.3	272.7	309.6	333.9
Transportation	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total End Use	**N/A**	**N/A**	**411.2**	**444.0**	**499.1**	**545.5**	**600.5**	**652.6**	**719.0**	**816.1**	**879.2**
Own Use	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	81.7
Electricity Generation	N/A	N/A	46.2	50.6	47.7	64.7	69.5	72.6	85.3	64.2	99.0
Steam Production	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Conversions	N/A	N/A	0.0	0.0	1.0	3.0	5.0	4.0	5.0	5.0	5.0
Total Primary	**N/A**	**N/A**	**457.4**	**494.6**	**547.8**	**613.1**	**675.0**	**729.3**	**809.3**	**885.3**	**1064.9**

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
Residential	264.8	296.5	286.6	309.0	315.6	329.9	331.0	403.0	415.5	426.8	430.7
Commercial	232.5	280.7	269.2	300.2	307.7	330.9	352.7	344.5	353.3	333.1	356.0
Petrochemical	90.4	87.2	92.8	95.6	104.4	123.6	166.8	175.6	192.9	195.2	175.7
Other Industrial	387.1	428.6	463.6	518.0	480.3	542.0	566.1	572.7	592.5	602.0	573.2
Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total End Use	**974.7**	**1092.9**	**1112.3**	**1222.7**	**1208.0**	**1326.5**	**1416.6**	**1495.8**	**1554.2**	**1557.1**	**1535.6**
Own Use	92.7	107.5	112.9	117.6	116.2	122.8	124.1	119.4	126.4	118.5	117.1
Electricity Generation	100.1	147.7	200.2	173.2	195.3	139.1	132.0	106.4	104.1	84.0	68.6
Steam Production	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.1
Other Conversions	8.0	11.0	10.0	11.0	11.0	11.0	12.0	14.0	15.0	16.0	17.0
Total Primary	**1175.5**	**1359.2**	**1435.3**	**1524.5**	**1530.5**	**1599.4**	**1684.7**	**1735.6**	**1799.7**	**1776.0**	**1738.4**

Table A6-18
Primary Demand for Natural Gas – Canada
Comparison of Submittors' Views

(Petajoules)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Amoco	N/A	1530	1580	1630	1680	1750	1950	2210	2530	2950
CPA	1768	N/A	N/A	N/A	N/A	N/A	2134	2373	N/A	N/A
Dome–Low	1774	1662	1787	1894	1953	2005	2185	2484	2796	N/A
Gulf	1718	1755	1842	1901	1947	1983	2110	2224	2430	N/A
Husky/NOVA	1934	1919	2008	2083	2147	2217	2444	2790	3136	3420
Imperial	1781	1832	2026	2090	2139	2158	2251	2415	2442	N/A
Petro-Canada–Base	1745	1724	1905	2127	2211	2290	2509	2795	3051	N/A
Shell	1711	1769	1876	1858	1902	1948	2097	2375	2622	N/A
Texaco	1961	1903	1989	2053	2116	2193	2405	2631	N/A	N/A
APMC	N/A	1902	2074	2168	2233	2296	2370	2601	2801	3017
NEB	1777	1766	1812	1908	1986	2068	2266	2507	2780	3059

- Demand data provided by NEB for 1982 are published actuals except for reprocessing fuel and pipeline transportation fuels.

Wherever possible 1983 data were tracked to established trends published in the Statistics Canada monthly catalogues.

Table A6-19
Historical Data – Natural Gas Supply and Demand – Canada

(Petajoules per year)

Year	Domestic Demand	Exports	Total Disposition	Supply[1] Capability
1960	371	121	492	—
1961	432	186	618	—
1962	470	377	847	—
1963	530	395	925	—
1964	602	431	1033	—
1965	695	445	1140	—
1966	750	475	1225	—
1967	777	564	1341	—
1968	851	664	1515	1550
1969	1021	748	1769	1800
1970	1179	858	2037	2100
1971	1258	1003	2261	2400
1972	1459	1110	2569	2600
1973	1612	1130	2742	2750
1974	1634	1054	2688	2900
1975	1710	1019	2729	3050
1976	1727	1027	2754	3200
1977	1795	1077	2872	3400
1978	1828	949	2777	3650
1979	1930	1077	3007	4000
1980	1907	857	2764	4400
1981	1920	820	2740	4600
1982	1962	844	2806	4850

(1) Estimated from previous NEB forecasts.

Table A6-20
Natural Gas Supply and Demand – Conventional Areas
NEB Projection

(Petajoules Per Year)

Year	(1) Net Sales	(2) Pipeline Fuel & Losses	(3) Repro-cessing Fuel	(4) Primary Gas Demand	(5) Repro-cessing Shrink-age	(6) Domestic Demand	(7) Exports	(8) Total Disposition	(9) Supply Capability	(10) Supply Capability Adjusted for Carry-forward
1983	1638	112	16	1766	165	1931	751	2682	5034	5034
1984	1679	115	17	1810	190	2001	782	2782	5094	5217
1985	1758	128	19	1906	225	2131	996	3127	5161	5404
1986	1827	136	21	1984	264	2247	1133	3381	5100	5449
1987	1879	162	25	2065	303	2368	1523	3892	5091	5530
1988	1943	171	25	2139	309	2448	1656	4104	5067	5569
1989	1986	181	27	2194	326	2519	1845	4364	4891	5443
1990	2042	184	27	2252	323	2575	1844	4419	4844	5424
1991	2085	174	24	2284	300	2583	1444	4027	4784	5340
1992	2150	166	23	2339	287	2627	1083	3710	4613	5200
1993	2210	159	21	2389	260	2650	707	3356	4418	5090
1994	2262	153	20	2435	245	2679	528	3207	4225	4950
1995	2311	146	18	2475	224	2699	367	3066	4054	4810
1996	2350	141	17	2508	209	2717	235	2952	3852	4680
1997	2391	140	16	2548	198	2746	171	2917	3649	4520
1998	2442	143	16	2601	193	2795	167	2961	3441	4400
1999	2500	146	16	2662	192	2854	167	3021	3270	4270
2000	2561	149	17	2727	194	2921	167	3088	3122	4100
2001	2626	147	17	2790	194	2984	42	3026	2971	3950
2002	2673	149	17	2839	195	3034	0	3034	2831	3790
2003	2719	151	17	2888	197	3085	0	3085	2680	3640
2004	2765	154	18	2937	199	3136	0	3136	2551	3470
2005	2811	157	18	2985	202	3187	0	3187	2422	3300

- Figures may not add due to rounding.
- Column 1 is the total domestic net sales in Canada excluding the Atlantic.
- Column 2 is the total pipeline fuel and losses for domestic and export sales.
- Column 3 is the forecast of fuel losses for reprocessing at the straddle plants.
- Column 4 is the forecast of primary gas demand.
- Column 5 is the forecast of reprocessing shrinkage at the straddle plants.
- Column 6 is the total forecast of domestic demand for natural gas
- Column 7 is the forecast of exports.
- Column 8 is the total demand for natural gas in Canada.
- Column 9 is the forecast of supply capability unrestricted by demand.
- Column 10 is the forecast of supply capability adjusted for the carry-forward of surplus supply.

Table A7-1
Historical Data – Production of Crude Oil and Equivalent

(Thousands of Cubic Metres Per Day)

	Conventional Light	Conventional Heavy	Synthetic	Experimental And Bitumen	Pentanes Plus	Total
1960	68.2	15.1	—	—	1.3	84.6
1961	81.1	16.2	—	—	2.4	99.7
1962	90.5	18.7	—	—	4.6	113.8
1963	93.0	20.8	—	—	8.1	121.9
1964	95.9	23.7	—	—	10.7	130.3
1965	101.6	25.7	—	—	11.9	139.2
1966	112.7	26.8	—	—	12.4	151.9
1967	125.1	27.9	.2	—	13.0	166.2
1968	132.2	30.1	2.3	—	14.1	178.7
1969	147.4	29.4	4.4	—	16.4	197.6
1970	166.1	31.2	5.2	—	18.9	221.4
1971	176.9	31.8	6.7	—	20.0	235.4
1972	203.6	32.3	8.1	—	26.0	270.0
1973	242.3	35.2	8.0	—	26.5	312.0
1974	230.0	30.3	7.3	—	25.3	292.9
1975	194.7	25.2	6.8	—	23.8	250.5
1976	174.1	24.6	7.6	1.2	20.9	228.4
1977	169.3	30.8	7.2	1.2	20.7	229.2
1978	165.6	32.2	8.9	1.2	18.5	226.4
1979	188.7	31.7	14.6	1.5	18.4	254.9
1980	173.7	31.1	20.3	1.5	16.6	243.2
1981	154.5	28.0	17.7	2.0	15.9	218.1
1982	150.7	28.7	19.1	3.2	15.5	217.2

Table A7-2
Historical Data
Established Reserves and Cumulative Production
Of Conventional Crude Oil

(Million Cubic Metres)

Year	Initial Established Reserves	Cumulative Production	Remaining Established Reserves
1960	1747.1	227.7	1519.4
1961	1753.7	262.7	1491.0
1962	1777.5	301.4	1476.1
1963	1805.9	342.3	1463.6
1964	1856.9	385.8	1471.1
1965	1960.4	432.1	1528.3
1966	2038.7	488.3	1550.4
1967	2154.2	543.7	1610.5
1968	2258.0	603.0	1655.0
1969	2324.5	665.3	1659.2
1970	2348.7	736.9	1611.8
1971	2387.5	814.1	1573.4
1972	2406.8	893.3	1513.5
1973	2416.9	996.3	1420.6
1974	2413.5	1093.3	1320.2
1975	2209.2	1179.9	1029.3
1976	2207.2	1253.1	954.1
1977	2245.8	1326.5	919.3
1978	2265.0	1398.5	866.5
1979	2287.5	1480.0	807.5
1980	2314.3	1554.6	759.7
1981	2336.1	1620.6	715.5
1982	2420.7	1685.0	735.7
1983[1]	2466.8	1752.3	714.5

Source CPA Data – 1960-1975 (probable reserves category)
Data from NEB Annual Reports – 1975-1982 (NEB data non-existent prior to 1975)

[1] Preliminary Estimate

Table A7-3

Productive Capacity of Crude Oil and Equivalent – Canada
NEB Projection

(Thousands of Cubic Metres Per Day)

	Light							Heavy					
	Established Reserves	Reserves Additions	Pentanes Plus	Synthetic[1]	Synthetic[2]	Frontier[3]	Sub total	Established Reserves	Reserves Additions	Diluent	Bitumen[4]	Upgrader Feedstock	Sub total
1983	165.1	—	9.0	23.5	—	—	197.6	34.4	—	5.5	4.0	—	43.9
1984	167.2	.5	7.8	24.2	—	—	199.7	37.3	.3	6.6	5.5	—	49.7
1985	153.1	3.9	8.2	25.0	—	—	190.2	34.7	1.8	7.2	7.0	—	50.7
1986	135.1	9.4	8.0	25.0	—	—	177.5	30.7	3.5	7.9	9.0	—	51.1
1987	118.5	16.0	9.0	25.0	—	—	168.5	27.1	5.4'	8.6	11.0	—	52.1
1988	103.9	21.5	8.3	28.5	3.0	—	165.2	23.9	7.2	9.4	13.0	(4.0)	49.5
1989	91.0	25.8	8.3	28.5	8.0	1.9	163.5	21.1	9.0	9.5	15.0	(9.0)	45.6
1990	80.0	29.1	8.4	28.5	14.0	1.9	161.9	18.7	10.7	8.7	17.0	(16.0)	39.1
1991	70.7	31.6	7.6	28.5	15.0	1.9	155.3	16.5	12.2	8.7	19.0	(17.0)	39.4
1992	62.7	33.4	6.7	33.5	15.0	1.9	153.2	14.7	13.6	9.2	21.0	(17.0)	41.5
1993	55.7	34.9	5.2	38.5	15.0	12.0	161.3	13.0	14.9	10.1	23.0	(17.0)	44.0
1994	49.9	35.9	4.2	38.5	15.0	35.0	178.5	11.5	16.0	10.5	24.0	(17.0)	45.0
1995	44.9	36.8	3.2	38.5	15.0	44.0	182.4	10.1	17.0	11.0	25.0	(17.0)	46.1
1996	40.6	37.3	2.3	38.5	15.0	44.0	177.7	8.9	17.9	11.4	26.0	(17.0)	47.2
1997	36.3	37.7	1.1	38.5	15.0	44.0	172.6	7.8	18.8	11.9	27.0	(17.0)	48.5
1998	33.0	38.0	.2	38.5	15.0	44.0	168.7	6.7	19.5	12.3	28.0	(17.0)	49.5
1999	29.7	38.4	(1.0)	43.5	15.0	44.0	169.6	5.7	20.1	12.7	29.0	(17.0)	50.5
2000	27.1	38.6	(2.0)	48.5	15.0	44.0	171.2	4.9	20.7	13.1	30.0	(17.0)	51.7
2001	24.7	38.8	(2.9)	48.5	15.0	44.0	168.1	4.2	21.3	13.7	31.0	(17.0)	53.2
2002	22.3	38.8	(3.8)	48.5	15.0	44.0	164.8	3.6	21.8	14.1	32.0	(17.0)	54.5
2003	20.1	38.8	(4.2)	48.5	15.0	44.0	162.2	3.2	22.2	14.6	33.0	(17.0)	56.0
2004	18.3	38.7	(4.6)	48.5	15.0	44.0	159.9	2.8	22.6	15.1	34.0	(17.0)	57.5
2005	16.5	38.6	(5.2)	48.5	15.0	44.0	157.4	2.5	23.0	15.7	35.0	(17.0)	59.2

(1) Integrated plants
(2) Regional upgraders.
(3) Pentanes plus from Sable Island has been included in frontier supply.
(4) Includes experimental.
(5) Approximately four thousand cubic metres per day of pentanes plus are not available for use as heavy oil diluent.

(Table A7-3 Cont'd)

	Total						
	Established Reserves	Reserves Additions	Pentanes Plus[5]	Oil Sands[5]	Frontier[3]	Upgrading Loss	Total
1983	199.5	—	14.5	27.5	—	—	241.5
1984	204.5	8	14.4	29.7	—	—	249.4
1985	187.8	5.7	15.4	32.0	—	—	240.9
1986	165.8	12.9	15.9	34.0	—	—	228.6
1987	145.6	21.4	17.6	36.0	—	—	220.6
1988	127.8	28.7	17.7	41.5	—	(1.0)	214.7
1989	112.1	34.8	17.8	43.5	1.9	(1.0)	209.1
1990	98.7	39.8	17.1	45.5	1.9	(2.0)	201.0
1991	87.2	43.8	16.3	47.5	1.9	(2.0)	194.7
1992	77.4	47.0	15.9	54.5	1.9	(2.0)	194.7
1993	68.7	49.8	15.3	61.5	12.0	(2.0)	205.3
1994	61.4	51.9	14.7	62.5	35.0	(2.0)	223.5
1995	55.0	53.8	14.2	63.5	44.0	(2.0)	228.5
1996	49.5	55.2	13.7	64.5	44.0	(2.0)	224.9
1997	44.1	56.5	13.0	65.5	44.0	(2.0)	221.1
1998	39.7	57.5	12.5	66.5	44.0	(2.0)	218.2
1999	35.4	58.5	11.7	72.5	44.0	(2.0)	220.1
2000	32.0	59.3	11.1	78.5	44.0	(2.0)	222.9
2001	28.9	60.1	10.8	79.5	44.0	(2.0)	221.3
2002	25.9	60.6	10.3	80.5	44.0	(2.0)	219.3
2003	23.3	61.0	10.4	81.5	44.0	(2.0)	218.2
2004	21.1	61.3	10.5	82.5	44.0	(2.0)	217.4
2005	19.0	61.6	10.5	83.5	44.0	(2.0)	216.6

Table A7-4

Conventional Crude Oil – Established Reserves and Productive Capacity by Province
NEB Projection

	(Millions of Cubic Meters)			(Cubic Meters per Day)									
							Productive Capacity						
	Initial Recoverable Reserves at 31/12/83	Cumulative Production to 31/12/82	Remaining Reserves	1983	1984	1985	1986	1987	1990	1995	2000	2005
Light Crude Oil												
Northwest Territories	39.900	4.327	35.573	482	538	1336	2361	3387	3900	3900	3900	2595
British Columbia	81 091	56.510	24.581	5811	5710	5397	4895	4438	3322	2036	1181	767
Alberta	1790.505	1238.913	551.592	148659	150497	137511	119167	102836	67270	35868	20559	12294
Saskatchewan	130.082	102.825	27.257	7948	8099	7478	6593	5818	4035	2151	848	436
Manitoba	32.093	21.496	10.597	1982	2122	2044	1961	1862	1440	938	594	375
Ontario	9.700	9.166	.534	218	187	161	139	119	76	36	16	0
Canada–Subtotal	**2083.371**	**1433.237**	**650.134**	**165100**	**167153**	**153927**	**135116**	**118460**	**80043**	**44929**	**27098**	**16467**
Heavy Crude Oil												
Alberta	117.217	63.024	54.193	15433	17395	16192	14132	12277	8057	3899	1558	640
Saskatchewan	265.939	187.884	78.055	18921	19822	18492	16529	14764	10592	6240	3371	1852
Manitoba	.244	.178	.066	48	37	28	22	17	3	0	0	0
Canada–Subtotal	**383.400**	**251.086**	**132.314**	**34402**	**37254**	**34712**	**30683**	**27058**	**18652**	**10139**	**4929**	**2492**
Total Crude Oil and Equivalent												
Northwest Territories	39.900	4.327	35.573	482	538	1336	2361	3387	3900	3900	3900	2595
British Columbia	81.091	56.510	24.581	5811	5710	5397	4895	4438	3322	2036	1181	767
Alberta	1907.722	1301.937	605.785	164092	167892	153703	133299	115113	75327	39767	22117	12934
Saskatchewan	396.021	290.709	105.312	26869	27921	25970	23122	20582	14627	8391	4219	2288
Manitoba	32 337	21.674	10.663	2030	2159	2072	1983	1879	1443	938	594	375
Ontario	9 700	9.166	.534	218	187	161	139	119	76	36	16	0
Canada–Total	**2466.771**	**1684.323**	**782.448**	**199502**	**204407**	**188639**	**165799**	**145518**	**98695**	**55068**	**32027**	**18959**
Preliminary Estimates as of 31/12/83												
Canada–Total	**2466.8**	**1752.3**	**714.5**									

Table A7-5
Conventional Crude Oil – Established Reserves and Productive Capacity by Pool
NEB Projection

Light Crude Oil

	Initial Recoverable Reserves at 31/12/83	Cumulative Production to 31/12/82	Remaining Reserves	1983	1984	1985	1986	1987	1990	1995	2000	20005
	(Millions of Cubic Meters)			(Cubic Meters per Day)								
Northwest Territories												
Norman Wells												
Norman Wells	39.900	4.327	35 573	482	538	1336	2361	3387	3900	3900	3900	2595
Pipeline Total	39.900	4.327	35.573	482	538	1336	2361	3387	3900	3900	3900	2595
Provincial Total	39.900	4.327	35.573	482	538	1336	2361	3387	3900	3900	3900	2595
British Columbia												
Blueberry Taylor Pipelines												
Aitken Creek-Gething A	1 000	0 913	0.087	40	36	32	28	25	17	0	0	0
Blueberry Debolt	2.249	1.969	0.280	148	143	115	91	71	34	0	0	0
Eagle Belloy (80%)	7.550	1.532	6.018	1180	1180	1158	1071	986	768	507	335	221
Inga-Inga Total	6.450	4 897	1.553	410	401	365	330	299	221	134	81	49
Stoddart West Total	1.043	0.224	0.819	175	175	168	154	141	108	70	45	29
Miscellaneous	0.562	0.262	0.300	41	38	34	32	29	24	18	14	12
Pipeline Total	18.854	9.797	9.057	1995	1973	1875	1708	1553	1176	731	477	312
Trans-Prairie Pipelines Ltd. – Beaton River												
Beatton R. Halfway Tot	1.650	1.288	0 362	120	120	113	98	85	56	27	0	0
Beatton R. W. Bluesky A	0.975	0.648	0.327	91	91	87	76	69	50	28	16	0
Eagle Belloy (20%)	1 877	0 383	1.494	295	295	287	265	244	190	125	83	54
Milligan Creek-Halfway	6.933	6.320	0.613	256	223	193	168	146	96	47	0	0
Peejay-Halfway	9 800	8 779	1 021	310	340	324	282	245	161	80	0	0
Weasel-Halfway	3 150	2 471	0 679	220	220	213	187	162	107	53	0	0
Wildmint-Halfway	1.615	1.289	0 326	139	119	103	88	76	48	23	0	0
Miscellaneous	1.716	1 449	0.267	125	109	95	82	71	46	0	0	0
Pipeline Total	27.716	22.627	5.089	1557	1518	1419	1250	1103	757	386	99	54

Table A7-5 (Cont'd)

	Initial Recoverable Reserves at 31/12/83	Cumulative Production to 31/12/82	Remaining Reserves	1983	1984	1985	1986	1987	1990	1995	2000	20005
	(Millions of Cubic Meters)			(Cubic Meters per Day)								
Trans-Prairie PipeLines Ltd. – Boundary Lake – Taylor												
Boundary Lake Unit No 1	17 500	11.620	5.880	1120	1120	1082	1005	933	747	516	356	246
Boundary Lake Unit No 2	11.300	8.829	2 471	665	639	580	526	478	357	220	135	83
Boundary Lake Dome 1 & 2	3.200	2.543	0.657	159	147	136	125	115	90	60	40	26
Miscellaneous	0.421	0.305	0.116	33	30	28	26	23	18	12	3	0
Pipeline Total	32.421	23.297	9.124	1977	1937	1827	1683	1551	1214	809	535	356
B.C. Trucked Oil	2.100	0.789	1.311	280	280	275	252	230	174	109	68	43
Pipeline Total	2.100	0.789	1.311	280	280	275	252	230	174	109	68	43
Provincial Total	81.091	56.510	24.581	5811	5710	5397	4895	4438	3322	2036	1181	767
Alberta												
Bow River Pipe Lines Ltd.												
Cressford Banff B	0.680	0.055	0.625	81	100	100	95	86	67	47	35	27
Provost Viking CAK	10 100	6 349	3 751	800	743	691	642	597	479	333	231	160
Miscellaneous & Undef	3.425	0.675	2.750	442	624	594	543	496	379	241	154	98
Pipeline Total	14.205	7.079	7.126	1323	1468	1386	1281	1181	926	622	420	286
Cremona Pipeline System												
Crossfield Cardium A	3.030	2.742	0 288	96	88	80	73	66	50	31	0	0
Garrington Card A & B (27%)	0.799	0.666	0.133	40	40	38	34	31	22	13	0	0
Garrington Mann (27%)	0.040	0.006	0.034	16	28	19	12	8	0	0	0	0
Garrington Viking A (27%)	0.269	0 029	0.240	60	80	76	66	57	37	17	8	0
Garrington Fld Othr (27%)	0.415	0 181	0.234	54	73	73	70	61	39	18	0	0
Harmattan East Rundle	11 650	9.462	2 188	725	900	829	683	562	313	118	0	0
Harmattan East Viking E	0.950	0.096	0 854	175	400	361	292	237	126	44	0	0
Harmattan Elkton Run C	11 500	7.998	3.502	857	1152	1300	1206	984	532	191	68	0
Olds Wabamun A	1 187	0.989	0.198	80	71	63	55	49	34	1	0	0
Westward Ho Rundle A	1 900	1.539	0 361	106	118	113	99	85	55	26	13	0
Miscellaneous & Undef	2.607	1.221	1 386	310	400	382	343	307	221	127	73	0
Pipeline Total	34.347	24.929	9.418	2520	3351	3338	2937	2451	1432	591	163	0

Table A7-5 (Cont'd)

	Initial Recoverable Reserves at 31/12/83	Cumulative Production to 31/12/82	Remaining Reserves	1983	1984	1985	1986	1987	1990	1995	2000	20005
	(Millions of Cubic Meters)			(Cubic Meters per Day)								
Federated Pipe Lines Ltd												
Carson Creek North Bhl A	6 400	4.405	1.995	1150	1199	997	688	475	156	0	0	0
Carson Creek North Bhl B	18 350	13.412	4.938	2123	1940	1690	1401	1161	661	259	101	0
Judy Creek Bhl A	48.000	41.794	6.206	2323	2030	1707	1451	1246	828	473	299	0
Judy Creek Bhl B	17.000	13.897	3.103	938	813	711	628	558	407	263	184	136
Judy Creek Viking A	0.810	0.362	0.448	185	185	167	136	110	58	20	7	0
Meekwap D-2A	4.200	2.205	1.995	560	600	590	522	454	298	148	73	0
Morinville D-3B 3%	0.056	0.033	0.023	8	10	9	7	5	2	0	0	0
Swan Hills Bhl A&B	105.000	76.549	28.451	6572	6048	5565	5120	4712	3671	2421	1597	1053
Swan Hills Bhl C	25 660	16.221	9.439	1595	1491	1396	1307	1226	1015	752	567	434
Swan Hills South Bhl A&B	66.000	47.440	18.560	4087	3653	3285	2970	2698	2073	1427	1041	793
Virginia Hills Bhl	20.658	18.133	2.525	1120	1120	1009	806	645	329	107	0	0
Virginia Hills Belloy A	4 328	0.425	3.903	800	1100	1100	1094	977	610	278	126	57
Miscellaneous & Undef	1.498	0.618	0.880	140	340	319	270	228	136	58	25	0
Pipeline Total	**317.960**	**235.494**	**82.466**	**21603**	**20533**	**18550**	**16406**	**14500**	**10251**	**6211**	**4024**	**2475**
Gibson Petroleum Company Limited												
Bellshill Blairmore	10.200	6 150	4.050	1000	1200	1154	1017	893	605	315	164	86
Thompson Lake Blairmore	0.794	0.556	0.238	95	95	88	73	60	34	13	0	0
Miscellaneous & Undef	0.242	0.013	0.229	62	85	79	69	60	39	19	0	0
Pipeline Total	**11.236**	**6.719**	**4.517**	**1157**	**1380**	**1323**	**1160**	**1014**	**678**	**348**	**164**	**86**
Gulf Alberta Pipeline												
Clive D-2A	3 100	1.791	1.309	285	310	301	274	249	187	116	72	45
Clive D-3A	6 960	4.190	2.770	615	615	594	542	494	373	234	147	92
Drumheller D-2A	1.700	1 149	0.551	190	200	184	155	131	78	33	14	0
Drumheller D-2B	2.260	1.053	1.207	400	550	514	407	320	155	46	0	0
Duhamel D-3B	1.370	1.098	0.272	172	197	145	92	59	15	0	0	0
Erskine D-3	3.800	3.343	0.457	131	123	114	104	96	73	47	0	0
Fenn Big Valley D-2A	51.840	37.399	14.441	6600	7649	5954	4591	3539	1622	442	0	0
Fenn Big Valley D-3F	2.200	1.718	0.482	200	220	196	156	124	62	19	0	0
Fenn West D-2A	1 390	1.024	0.366	140	160	147	118	95	49	16	0	0
Fenn West D-3C	0.480	0.015	0.465	170	150	141	121	103	65	30	13	6
Fenn West D-3E	0.796	0.000	0.796	185	220	220	220	220	138	51	18	6
Hussar Glauconitic A	3.400	2.546	0.854	280	320	303	254	212	124	50	13	0
Hussar Field Other	1.333	0.654	0.679	100	120	120	120	120	108	70	49	36
Joffre D-2	8.000	6.261	1.739	365	364	346	316	290	225	152	105	75
Rich D-3	3.100	0.093	3.007	525	600	600	600	600	578	275	130	61
Stettler D-2A	4.200	3.776	0.424	139	128	116	104	93	67	38	0	0
Stettler D-3A	3.690	2.837	0.853	260	249	222	198	176	125	70	39	0
Wayne-Rosedale BSL QTZ B	0.908	0.314	0.594	140	140	135	122	110	82	52	34	23
Wayne-Rosedale Fld Other	0.696	0.101	0.595	91	100	100	100	100	83	55	39	29
West Drumheller D-2A	4 800	4.082	0.718	220	280	261	222	189	117	52	0	0
Wood River D-2C	0.518	0.216	0.302	100	100	94	81	69	43	20	9	0
Miscellaneous & Undef	26.743	18.033	8.710	1570	2100	2040	1851	1675	1240	752	456	276
Pipeline Total	**133.284**	**91.693**	**41.591**	**12878**	**14898**	**12854**	**10757**	**9072**	**5621**	**2630**	**1145**	**654**

Table A7-5 (Cont'd)

	Initial Recoverable Reserves at 31/12/83	Cumulative Production to 31/12/82	Remaining Reserves	1983	1984	1985	1986	1987	1990	1995	2000	20005
	(Millions of Cubic Meters)						(Cubic Meters per Day)					
The Imperial Pipe Line Company, Limited – Ellerslie												
Acheson D-3A	20.450	14.939	5.511	1775	1900	1829	1558	1315	789	337	144	17
Acheson Field Other	1.098	0.727	0.371	87	110	104	93	83	59	33	18	0
Acheson East Blairmore B	0.597	0.253	0.344	140	139	125	103	85	48	18	0	0
Golden Spike D-3A	28 500	27.344	1.156	430	360	337	280	237	157	96	66	0
Morinville D 3B 97%	1 630	1.062	0.568	354	337	251	180	130	48	2	0	0
St. Albert D-3A	2.150	2.055	0.095	73	59	47	38	30	0	0	0	0
St. Albert D-3B	1.000	0.804	0.196	108	96	76	61	48	24	0	0	0
Yekau Lake D-3A	0.750	0.541	0.209	85	108	88	68	53	25	7	0	0
Miscellaneous & Undef	3.695	2.286	1.409	280	330	330	330	319	224	123	67	37
Pipeline Total	**59.870**	**50.011**	**9.859**	**3334**	**3440**	**3191**	**2715**	**2304**	**1377**	**618**	**297**	**54**
The Imperial Pipe Line Company, Limited – Excelsior												
Excelsior D-2	4.300	3.981	0.319	190	145	113	90	73	42	0	0	0
Fairydell-Bon Accord D3A	2 070	1.615	0.455	145	128	114	101	90	64	38	23	0
Miscellaneous & Undef	0.827	0.686	0.141	56	60	52	45	38	24	0	0	0
Pipeline Total	**7.197**	**6.282**	**0.915**	**392**	**334**	**280**	**237**	**202**	**132**	**38**	**23**	**0**
The Imperial Pipe Line Company, Limited – Leduc												
Leduc Woodbend D-2A	14.200	13.948	0.252	109	91	78	68	60	44	0	0	0
Leduc Woodbend D-3A	39.300	37.633	1.667	895	793	675	551	449	243	0	0	0
Leduc Woodbend D-3F	0.795	0.505	0.290	114	114	106	91	77	48	0	0	0
Miscellaneous & Undef	6.105	5.848	0.257	75	84	80	70	60	40	19	4	0
Pipeline Total	**60.400**	**57.934**	**2.466**	**1193**	**1083**	**941**	**780**	**648**	**376**	**19**	**4**	**0**
The Imperial Pipeline Company, Limited – Redwater												
Redwater D-3	128.000	118.549	9.451	4234	3448	2836	2354	1970	1206	596	328	0
Redwater UML Viking A	0.371	0 057	0.314	68	115	107	92	79	50	23	0	0
Miscellaneous & Undef	0.709	0.136	0.573	107	120	120	120	114	84	51	31	18
Pipeline Total	**129.080**	**118.742**	**10.338**	**4409**	**3683**	**3063**	**2566**	**2164**	**1341**	**672**	**359**	**18**
Murphy Milk River Pipeline												
Coutts Total	0.600	0.394	0.206	100	90	74	61	50	27	10	0	0
Manyberries Total	1 450	0.455	0.995	250	360	334	285	243	150	67	30	0
Miscellaneous & Undef	2.161	0 970	1.191	160	210	210	210	209	168	113	75	50
Pipeline Total	**4.211**	**1.819**	**2.392**	**510**	**660**	**619**	**556**	**502**	**346**	**191**	**106**	**50**

Table A7-5 (Cont'd)

	Initial Recoverable Reserves at 31/12/83	Cumulative Production to 31/12/82	Remaining Reserves	1983	1984	1985	1986	1987	1990	1995	2000	20005
	(Millions of Cubic Meters)			(Cubic Meters per Day)								
Norcen Energy Resources Ltd.												
Joarcam Viking	17.000	14.336	2.664	825	900	845	731	632	409	198	21	0
Pipeline Total	17.000	14.336	2.664	825	900	845	731	632	409	198	21	0
Peace River Oil Pipe Line Co. Ltd.												
Ante Creek BHL	2 550	1.524	1.026	200	220	213	197	182	144	97	66	44
Ante Creek BHL B	0.550	0.220	0.330	127	196	154	114	84	34	7	0	0
Bonanza Boundary A	0.505	0.098	0.407	110	190	173	140	113	59	20	0	0
Carrot Creek Field Total	1.538	0.192	1 346	205	450	421	366	317	207	101	50	24
Cherhill Field Total	2 200	0.485	1.715	195	240	240	240	240	206	136	96	71
Edson Field Total	1.572	0.628	0.944	317	340	317	274	237	153	73	0	0
Fox Creek BHL A	0.375	0.081	0.294	85	110	101	85	71	42	17	7	0
Gift Slave Point A	0.600	0 022	0.578	62	160	159	145	128	89	49	27	14
Goose River BHL A	7 160	4.760	2.400	660	750	705	614	536	355	179	90	12
Kakwa A Cardium A	0 766	0.039	0 727	105	150	149	142	130	99	63	40	25
Kaybob BHL A	16.275	13.723	2.552	1525	1300	1142	863	652	281	0	0	0
Kaybob South Triassic A	13.900	8.956	4.944	1620	1620	1512	1312	1138	743	365	179	0
Nipisi Gilwood A (52%)	25 064	16.045	9.019	2510	3120	3120	2944	2424	1330	489	180	5
Nipisi Field Other (52%)	1.449	0.490	0.959	153	416	390	321	263	144	53	2	0
Pine Creek Field Total	1 040	0.400	0.640	143	128	116	105	97	77	56	44	36
Pouce Coupe S. Bdry B	0.624	0.081	0.543	150	170	167	148	127	81	38	18	0
Red Earth Granite Wash A	4.000	2.507	1.493	325	325	317	292	268	208	136	89	58
Red Earth Slave Pt A	0.693	0.342	0.351	85	85	83	76	69	53	33	21	0
Red Earth Field Other	3.324	1.498	1.826	275	310	310	300	275	215	150	109	82
Seal Slave Point A	0.560	0.122	0.438	98	135	127	111	98	66	34	18	0
Simonette D-3	5.850	5 239	0.611	325	309	272	212	165	78	0	0	0
Snipe Lake BHL	10.000	7.333	2 667	560	550	540	494	450	346	235	168	125
Sturgeon Lake D-3	3.600	3 001	0.599	243	212	185	162	141	94	47	0	0
Sturgeon Lake South D-3	25.500	17 076	8.424	1885	1800	1734	1592	1461	1128	734	477	310
Tangent Field Total	0.695	0.002	0.693	145	260	243	205	172	101	42	17	7
Utikuma KR Sand A(16%)	1 040	0.549	0.491	153	200	189	155	126	68	24	8	0
Utikuma KR Sand N(16%)	0.163	0.045	0 118	48	47	43	35	28	15	5	1	0
Utikuma Field Other(16%)	0.412	0.063	0.349	66	72	72	72	72	55	30	16	9
Valhalla Doe Creek I	1.095	0.004	1.091	130	260	260	254	230	165	95	55	31
Wembley Halfway B	1 250	0.169	1 081	200	300	300	282	247	167	87	45	23
Windfall D-3A	2.550	1 784	0.766	370	400	352	261	193	78	17	0	0
Miscellaneous & Undef	10.406	3.734	6.672	975	1350	1350	1350	1341	1001	592	350	207
Pipeline Total	147.306	91.212	56.094	14053	16178	15469	13875	12089	7897	4019	2184	1093

Table A7-5 (Cont'd)

	Initial Recoverable Reserves at 31/12/83	Cumulative Production to 31/12/82	Remaining Reserves	1983	1984	1985	1986	1987	1990	1995	2000	20005
	(Millions of Cubic Meters)						(Cubic Meters per Day)					
				Pembina Pipeline Company Ltd								
Bigoray Cardium B	0.800	0.108	0 692	165	197	178	157	140	97	53	29	16
Bigoray Nisku B	0 900	0.204	0.696	185	180	180	175	154	103	52	26	13
Bigoray Nisku D	0.660	0.249	0.411	103	70	70	70	70	70	42	21	10
Bigoray Nisku E	0.600	0.166	0.434	115	100	88	78	69	52	35	25	19
Bigoray Nisku F	1.350	0.444	0.906	320	400	361	290	232	120	40	0	0
Bigoray Nisku H	0.660	0.077	0.583	135	150	150	149	137	93	48	25	0
Bigoray Nisku K	0 385	0.062	0 323	90	120	112	96	82	51	23	0	0
Brazeau River-Nisku A	3.975	1 002	2.973	935	1150	1070	885	730	410	157	60	23
Brazeau River-Nisku B	0.920	0.239	0.681	280	350	310	235	179	78	19	0	0
Brazeau River-Nisku D	1 530	0.310	1.220	280	400	373	322	279	180	87	42	20
Brazeau River-Nisku E	1.500	0.361	1 139	255	440	409	342	286	168	69	28	0
Crystal Viking A	3.177	0.107	3.070	455	650	650	650	650	514	265	142	79
Cyn-Pem Cardium A	2 330	1.693	0 637	265	280	254	204	164	84	28	0	0
Cyn-Pem Cardium D	0.445	0 028	0.417	102	130	129	117	101	64	30	14	0
Cyn-Pem Field Other	0 744	0 118	0.626	75	220	205	176	152	96	45	21	10
Highvale Lower Mann A	0.625	0.088	0.537	124	122	120	116	105	80	50	32	12
Minnehik Buck Lk Fld Ttl	0.736	0.079	0.657	120	180	172	156	142	106	66	40	0
Niton Basal Quartz B	1.520	0 780	0.740	156	141	128	117	107	84	59	44	34
Pembina Cardium	228 000	151.711	76.289	7640	7299	7106	6749	6417	5558	4465	3666	3064
Pembina Keystone BR B	8.000	5.233	2.767	622	553	495	445	402	303	201	141	104
Pembina Keystone BR C	2 782	1 627	1.155	367	340	322	283	249	168	88	45	4
Pembina Keystone BR I	1.600	0 821	0.779	102	110	110	110	110	98	76	59	46
Pembina Keystone BR M	1.470	0.878	0.592	115	115	115	115	114	91	58	37	23
Pembina Keystone BR U	1 800	0.830	0.970	165	180	180	180	180	151	96	61	39
Pembina Keystone BR X	1.316	0.290	1 026	120	120	120	120	120	105	78	62	50
Pembina Belly Rvr Other	2.653	1.033	1 620	290	320	320	320	320	264	180	133	0
Pembina Nisku A	1.430	0.370	1.060	340	500	444	349	275	133	40	12	0
Pembina Nisku C	0.715	0.213	0.502	172	210	192	157	128	69	24	0	0
Pembina Nisku D	2 230	0.709	1.521	442	500	464	400	345	220	104	49	23
Pembina Nisku G	2 100	0 236	1.864	477	502	527	528	458	283	127	57	25
Pembina Nisku J	0 564	0 114	0.450	130	115	115	115	109	70	33	15	- 7
Pembina Nisku K	1 700	0.279	1.421	306	318	325	325	325	276	112	45	18
Pembina Nisku L	1 930	0.367	1.563	450	550	509	431	364	221	95	41	18
Pembina Nisku M	2 140	0.092	2 048	360	620	620	596	512	316	142	63	28
Pembina Nisku O	1 190	0.066	1 124	50	250	250	244	222	164	99	60	36
Pembina Nisku P	3.190	0.134	3.056	125	720	720	720	720	563	266	125	59
Pembina Ostracod E	0.442	0.061	0.381	125	150	137	113	94	53	20	7	0
Westpem Nisku A	1.990	0.250	1.740	475	574	522	449	387	246	116	55	26
Westpem Nisku C	2 040	0 357	1.683	450	600	560	473	399	239	102	43	18
Westpem Nisku D	1 540	0 215	1.325	367	450	426	363	308	189	83	37	16
Will-Green Card A (70%)	18 900	10.079	8 821	1010	970	930	856	792	641	476	372	301
Will-Green Vkg A (70%)	0 390	0.203	0.187	66	70	65	56	48	30	11	0	0
Nisku Miscellaneous	4.174	0.755	3.419	468	756	900	900	885	576	272	128	60
Pembina Pipeline Msc & Und	5.846	1.443	4 403	1000	1150	1088	972	869	621	355	202	115
Pipeline Total	322.989	184.481	138.508	20400	23327	22536	20721	18948	14120	8909	6084	4331

Table A7-5 (Cont'd)

	Initial Recoverable Reserves at 31/12/83	Cumulative Production to 31/12/82	Remaining Reserves	1983	1984	1985	1986	1987	1990	1995	2000	20005
	(Millions of Cubic Meters)			(Cubic Meters per Day)								
Rainbow Pipeline Company Ltd.												
Evi Field Total	2.405	0.212	2.193	375	410	410	410	410	333	202	122	74
Golden-Slave Pt A	2.500	1.374	1.126	410	449	405	333	274	152	57	21	0
Mitsue-Gilwood A	58.000	35.417	22.583	4743	4199	3741	3351	3018	2265	1504	1065	790
Nipisi-Gilwood A (48%)	23.140	14.811	8.329	2640	2880	2880	2670	2189	1201	442	162	0
Nipisi Field Other (48%)	1.338	0.452	0.886	141	384	360	296	242	133	49	4	0
Rainbow Kr A	11.298	7.273	4.025	1308	1127	975	847	739	500	278	164	102
Rainbow Kr B	20.400	16.265	4.135	1844	1736	1516	1222	986	517	176	60	17
IS No. 1 Other	11.500	8.256	3.244	925	925	892	786	690	467	244	127	66
Rainbow Kr F	19.100	12.531	6.569	2140	1780	1677	1480	1306	897	480	257	137
Rainbow Kr I	3.100	2.033	1.067	394	382	346	291	246	147	62	26	11
Rainbow Kr N	0.650	0.431	0.219	115	155	112	75	50	15	0	0	0
Rainbow Kr AA	8.000	6.136	1.864	323	278	244	217	195	149	106	82	66
Rainbow Kr II	1.920	1.574	0.346	85	94	84	72	62	42	26	18	13
IS No. 11 Other	3.560	2.524	1.036	300	419	376	312	259	149	59	23	0
IS No. 2 Total	4.710	2.555	2.155	850	850	771	631	516	283	104	38	14
Rainbow Field Other	8.072	4.415	3.657	1100	1397	1255	1058	893	536	229	97	0
Rainbow South-Kr A	1.750	1.580	0.170	60	64	60	54	48	37	0	0	0
Rainbow South-Kr B	4.000	2.785	1.215	425	450	422	355	298	176	73	8	0
Rainbow South-Kr E	2.300	1.985	0.315	156	170	151	116	89	41	0	0	0
Rainbow S. Fld Other	3.100	1.622	1.478	345	430	406	358	315	216	115	61	32
Shekilie Field Total	2.925	0.822	2.103	370	450	450	450	450	333	183	100	55
Slave-Slave Pt G	0.648	0.109	0.539	124	149	140	124	110	77	42	23	12
Utikuma Lk Kr Sand A 84%	5.360	2.884	2.476	805	1050	951	775	631	341	122	32	0
Utikuma Lk Kr Sand N 84%	0.857	0.237	0.620	252	252	227	185	151	81	29	10	0
Utikuma Field Other 84%	2.161	0.331	1.830	344	378	378	378	378	294	161	88	48
Virgo Field Total	7.215	5.235	1.980	475	525	525	523	478	314	156	77	8
Zama Field Total	13.956	9.840	4.116	1075	1350	1305	1147	1002	668	340	0	0
Miscellaneous & Undef	3.844	2.132	1.712	330	400	400	385	349	259	157	95	57
Pipeline Total	227.809	145.821	81.988	22455	23139	21468	18914	16387	10636	5404	2770	1510

Table A7-5 (Cont'd)

	Initial Recoverable Reserves at 31/12/83	Cumulative Production to 31/12/82	Remaining Reserves	1983	1984	1985	1986	1987	1990	1995	2000	20005
	(Millions of Cubic Meters)						(Cubic Meters per Day)					
				Rangeland Pipeline Company Limited								
Caroline Cardium E	1.560	0.541	1.019	275	450	410	334	272	147	52	0	0
Caroline Viking A	1.180	0.687	0.493	112	140	134	121	109	80	48	9	0
Ferrier Cardium D	3.000	1.318	1.682	217	240	234	220	208	175	134	104	82
Ferrier Cardium E	4.850	1.808	3.042	410	450	441	403	368	285	198	145	111
Ferrier Cardium G	3.494	0.478	3.016	297	340	340	340	336	274	205	163	135
Garrington Card A&B(73%)	2.160	1.800	0.360	109	108	101	91	82	60	36	0	0
Garrington Mann D (73%)	0.110	0.017	0.093	43	77	53	34	21	2	0	0	0
Garrington Viking A(73%)	0.728	0.080	0.648	163	219	204	177	153	99	48	23	0
Garrington Fld Othr(73%)	1.122	0.490	0.632	146	197	197	192	167	107	50	0	0
Gilby Basal Mann. B	1.300	0.830	0.470	89	115	110	101	92	71	45	29	0
Gilby Jurassic B	3.670	2.153	1.517	277	253	233	214	198	159	115	87	68
Gilby Field Other	4.467	3.400	1.067	172	193	174	158	143	111	77	57	44
Innisfail D-3	11.820	10.176	1.644	742	750	671	530	418	205	62	0	0
Med River Glauconitic A	2.110	1.158	0.952	285	285	271	238	210	143	76	40	0
Med River Jurassic A	1.800	1.461	0.339	150	160	144	116	93	48	0	0	0
Med River Jurassic C	2.040	1.149	0.891	211	220	214	194	176	130	79	48	29
Med River Jurassic D	2.130	1.320	0.810	180	194	179	158	141	101	63	41	29
Med River Pekisco E	0.791	0.413	0.378	81	75	70	64	60	47	32	22	14
Med River Pekisco I	1.100	0.640	0.460	96	109	102	93	85	64	40	25	16
Med River Pekisco N	0.680	0.107	0.573	95	95	92	85	77	61	43	32	24
Medicine Rvr Fld Other	2.833	1.479	1.354	327	465	460	406	346	214	96	0	0
Ricinus Cardium A	2.880	0.845	2.035	337	400	384	348	317	241	160	111	79
Ricinus Field Other	2.835	1.116	1.719	335	370	352	317	287	214	136	90	61
Sundre Rundle A	5.200	4.333	0.867	360	360	330	273	225	127	32	0	0
Sylvan Lake Pekisco B	2.300	1.248	1.052	235	230	220	202	186	144	94	61	40
Sylvan Lake Field Other	3.398	1.760	1.638	355	360	349	317	288	218	141	94	65
Will-Green Card A 30%	8.100	4.319	3.781	433	417	400	368	341	276	205	160	129
Will-Green Viking A 30%	0.160	0.087	0.073	28	29	25	21	18	12	0	0	0
Wimborne D-3A	2.800	2.036	0.764	400	390	344	255	189	76	17	0	0
Miscellaneous & Undef	4.706	2.003	2.703	550	650	627	568	514	381	231	140	85
Pipeline Total	**85.324**	**49.252**	**36.072**	**7516**	**8345**	**7877**	**6952**	**6133**	**4284**	**2528**	**1490**	**1019**
				Texaco Canada Inc.								
Bonnie Glen D-3A	84.700	64.508	20.192	11050	11587	9052	6573	4773	1827	368	0	0
Glen Park D-3A	3.424	2.699	0.725	380	449	367	254	176	59	0	0	0
Westerose D-3	22.000	14.978	7.022	2670	4000	3449	2509	1826	703	143	13	0
Wizard Lake D-3A	59.000	42.341	16.659	6350	7000	6332	5107	4119	2161	737	251	2
Miscellaneous & Undef	1.996	1.533	0.463	110	170	170	170	153	72	20	0	0
Pipeline Total	**171.120**	**126.059**	**45.061**	**20560**	**23206**	**19370**	**14615**	**11049**	**4824**	**1270**	**264**	**2**
				Trans-Prairie Pipelines Ltd. – Boundary Lake South								
Boundary L.South Tria.C	0.640	0.285	0.355	58	52	48	44	41	33	25	20	17
Boundary L.South Tria.E	3.782	1.934	1.848	400	400	389	355	324	246	155	98	61
Boundary L.South Tria.H	0.649	0.107	0.542	80	80	80	80	79	66	48	35	26
Miscellaneous & Undef	0.345	0.040	0.305	62	97	87	76	67	45	23	12	6
Pipeline Total	**5.416**	**2.366**	**3.050**	**600**	**630**	**604**	**556**	**512**	**391**	**253**	**166**	**111**

Table A7-5 (Cont'd)

	Initial Recoverable Reserves at 31/12/83	Cumulative Production to 31/12/82	Remaining Reserves	1983	1984	1985	1986	1987	1990	1995	2000	20005
	(Millions of Cubic Meters)			(Cubic Meters per Day)								
Twining Pipeline Division												
Twining-Rundle A & LM A	5.600	2.231	3.369	516	474	438	407	379	314	241	194	161
Twining North Rundle	1 900	0.808	1 092	262	249	233	208	187	140	93	66	50
Miscellaneous & Undef	0.549	0.184	0 365	80	89	83	75	68	50	30	18	11
Pipeline Total	8.049	3.223	4.826	859	814	756	691	635	505	365	279	222
Valley Pipeline												
Turner Valley Total	25.485	21.238	4.247	500	500	500	500	500	489	385	303	238
Pipeline Total	25.485	21.238	4.247	500	500	500	500	500	489	385	303	238
Truck and Tank Light												
Truck & Tank Light	0.717	0.223	0.494	70	120	119	113	102	74	44	26	15
Pipeline Total	0.717	0.223	0.494	70	120	119	113	102	74	44	26	15
Light Undefined and Confidential												
Light Undef & Confid	7 500	0.000	7 500	1250	2500	2415	2096	1804	1150	543	256	121
Pipeline Total	7.500	0.000	7.500	1250	2500	2415	2096	1804	1150	543	256	121
Provincial Total	790.505	1238.913	551.592	138414	150497	137511	119167	102836	67270	35868	20559	12294
Saskatchewan												
Bow River Pipeline Ltd.												
Dodsland Eagle L Vol	2.250	1.659	0.591	119	108	100	92	86	71	54	44	37
Dodsland Gleneath Unit	2.400	1.587	0.813	138	138	133	123	114	93	70	55	44
Dodsland Viking Sand Non	4 820	1 633	3.187	985	1150	1100	951	818	522	246	0	0
Eureka Viking South Unit	1.380	1.016	0.364	80	73	67	62	57	46	34	27	22
Miscellaneous Total	2.700	1.720	0.980	245	370	348	299	256	160	74	0	0
Pipeline Total	13.550	7.615	5.935	1568	1840	1750	1528	1333	894	480	126	103

Table A7-5 (Cont'd)

	Initial Recoverable Reserves at 31/12/83	Cumulative Production to 31/12/82	Remaining Reserves	1983	1984	1985	1986	1987	1990	1995	2000	20005
	(Millions of Cubic Meters)			(Cubic Meters per Day)								
Westspur Pipeline Company												
Alameda-Midale East Unit	1.816	1.386	0.430	81	81	79	74	70	58	43	31	23
Alida East – Unit	1.992	1.711	0.281	71	65	61	56	52	41	28	19	0
Alida West – Alida Non	2.005	1.663	0.342	97	94	88	79	71	52	30	18	0
Browning-Frob Alida Non	1.100	0.733	0.367	77	77	74	69	64	51	35	24	17
Carnduff -Midale E Unit	2.800	2.553	0.247	94	91	85	75	67	46	0	0	0
Elmore – Frob Vol Unit	2.020	1.556	0.464	126	120	111	101	91	68	41	25	1
Flat Lk Ratcliffe Vol Un	2.100	1.314	0.786	192	189	179	163	148	111	69	43	26
Freda Lake Ratcliffe Non	0.690	0.346	0.344	72	94	88	79	72	53	32	19	0
Hastings – Frob Non-Unit	1.858	1.597	0.261	102	110	101	84	70	41	0	0	0
Hastings Frobisher Units	2.655	2.306	0.349	107	104	94	85	77	57	34	0	0
Ingoldsby-Frob Vol Unit	2.600	2.080	0.520	95	88	82	76	71	59	46	37	30
Kenosee-Tilston Vol Unit	2.160	1.657	0.503	190	167	146	128	113	76	40	0	0
Nottingham Field Total	2.718	2.104	0.614	121	114	107	101	95	80	59	44	32
Parkman-Til Souris V Non	3.400	2.735	0.665	232	220	202	177	156	106	56	0	0
Queensdale East-Frob Non	5.500	3.740	1.760	340	340	329	305	282	224	152	103	70
Rosebank-Frob Vol Unit 1	3.700	3.376	0.324	113	102	91	82	73	53	31	0	0
Sherwood-Frobisher Non	1.950	1.547	0.403	90	100	95	86	77	57	34	20	12
Star Valley-Frob Ali Non	1.650	0.997	0.653	165	175	166	149	133	95	54	31	17
Steelman Midale Unit 1A	8.900	7.876	1.024	340	305	273	244	219	157	90	39	0
Steelman Midale Unit 2	8.400	7.364	1.036	280	277	255	230	207	151	90	53	15
Steelman Midale Unit 3	4.350	3.768	0.582	184	180	167	148	132	92	51	0	0
Steelman Midale Unit 4	5.650	4.434	1.216	312	291	268	246	226	176	115	75	22
Steelman Midale Unit 6	9.120	8.454	0.666	243	223	197	175	154	107	58	0	0
Steelman-Midale Non-Unit	0.850	0.563	0.287	115	125	115	97	82	50	0	0	0
Steelman Field Other	5.540	4.820	0.720	265	299	270	228	192	115	0	0	0
Viewfield-Frob Alida Non	0.700	0.387	0.313	87	79	72	65	59	44	27	17	10
Willmar-Frob Ali Non-Un	3.200	2.534	0.666	223	210	191	168	147	100	52	27	0
Willmar-Frob-Ali Units	2.104	1.606	0.498	109	102	95	89	83	67	48	34	24
Workman-Frob Vol Unit 1	1.820	1.557	0.263	75	68	61	55	50	38	25	17	0
Workman-Frob Non-Unit	1.419	0.880	0.539	120	112	104	97	90	73	51	36	25
Miscellaneous	21.765	17.566	4.199	1650	1644	1467	1237	1044	627	268	0	0
Pipeline Total	116.532	95.210	21.322	6379	6259	5728	5065	4484	3140	1671	721	332
Provincial Total	130.082	102.825	27.257	7948	8099	7478	6593	5818	4035	2151	848	436

Table A7-5 (Cont'd)

	Initial Recoverable Reserves at 31/12/83	Cumulative Production to 31/12/82	Remaining Reserves	1983	1984	1985	1986	1987	1990	1995	2000	20005
	(Millions of Cubic Meters)			(Cubic Meters per Day)								
Manitoba												
Trans-Prairie Pipelines Ltd.												
Daly Field Total	4 100	3.497	0.603	185	184	168	149	132	92	50	27	0
Virden Field Total	22 400	17.165	5.235	1030	963	901	843	788	645	462	330	236
Waskada Field Total	4 500	0.218	4.282	655	850	850	850	834	622	377	229	138
Manitoba Miscellaneous	1.093	0.616	0.477	112	125	124	118	107	79	48	6	0
Pipeline Total	32.093	21.496	10.597	1982	2122	2044	1961	1862	1440	938	594	375
Provincial Total	32.093	21.496	10.597	1982	2122	2044	1961	1862	1440	938	594	375
Ontario												
Ontario Total	9.700	9.166	0.534	218	187	161	139	119	76	36	16	0
Pipeline Total	9.700	9.166	0.534	218	187	161	139	119	76	36	16	0
Provincial Total	9.700	9.166	0.534	218	187	161	139	119	76	36	16	0
Canada Total	2083.371	1433.237	650.134	154856	167156	153929	135117	118460	80042	44931	27099	16468

Heavy Crude Oil

	Initial Recoverable Reserves at 31/12/83	Cumulative Production to 31/12/82	Remaining Reserves	1983	1984	1985	1986	1987	1990	1995	2000	2005
	(Millions of Cubic Meters)			(Cubic Meters per Day)								
Alberta												
Bow River Pipelines Ltd												
Alderson Field Total	2.347	0.955	1.392	340	470	468	421	358	222	99	0	0
Bantry Mannville A & D	8.300	5.535	2.765	615	650	624	567	515	386	239	147	91
Cessford Total Heavy	6.075	3.672	2.403	527	635	602	539	483	347	200	115	66
Chin Coulee Bsl Mann A	0.910	0.675	0.235	103	97	87	73	62	37	0	0	0
Countess Upper Mann B	1.300	0.906	0.394	191	159	132	109	91	52	20	0	0
Countess Upper Mann D	6.000	3.899	2.101	650	650	609	531	462	305	153	76	24
Countess Upper Mann H	2.100	1.669	0.431	204	199	177	143	116	61	0	0	0
Countess Upper Mann O	1.000	0.445	0.555	195	194	176	150	128	79	35	16	0
Grand Forks Upper Mann B	1.350	0.711	0.639	210	220	204	175	149	94	43	19	0
Grand Forks Lower Mann A	1.000	0.296	0.704	200	280	256	212	176	100	39	15	0
Grand Forks Lower Mann D	5.900	3.395	2.505	900	900	833	705	597	363	158	66	0
Grand Forks Lower Mann E	1.540	0.559	0.981	375	375	346	289	241	140	57	0	0
Grand Forks Lower Mann G	0.901	0.263	0.638	230	256	214	178	149	87	35	14	0
Grand Forks Lower Mann K	2.040	1.039	1.001	450	406	337	280	233	133	52	15	0
Grand Forks Field Other	1.932	0.743	1.189	325	560	509	410	331	173	46	0	0
Hays Lower Mann A	1.650	1.258	0.392	140	140	133	115	99	63	29	0	0
Horsefly Lake Mannville	1.130	0.815	0.315	130	117	102	89	77	51	19	0	0
Jenner Field Total	1.228	0.828	0.400	120	120	119	107	94	63	33	0	0
Lathom Upper Mann A	2.200	1.383	0.817	300	300	278	234	198	118	50	0	0
Little Bow Field Total	1.524	0.399	1.125	210	270	266	245	223	168	105	65	41
Sibbald Upper Mannville C	0.410	0.060	0.350	102	130	121	103	88	54	24	0	0
Suffield Field Total	0.589	0.179	0.410	115	149	134	117	101	66	33	0	0
Taber Mann D	2.300	1.525	0.775	236	212	189	170	152	109	63	36	20
Taber North Glauc A	1.590	0.105	1.485	260	330	330	330	326	232	127	69	38
Taber North Field Other	1.409	0.525	0.884	265	279	258	227	199	135	70	36	0
Taber South Mann A	1.100	0.832	0.268	81	73	67	61	55	42	26	12	0
Taber South Mann B	2.025	1.731	0.294	125	115	98	83	71	44	19	0	0
Wrentham Field Total	0.611	0.303	0.308	87	119	109	93	79	49	22	0	0
Miscellaneous & Undef	6.707	3.208	3.499	1312	1450	1316	1080	886	489	181	0	0
Pipeline Total	67.168	37.913	29.255	9002	9862	9107	7849	6752	4274	1989	709	282

Table A7-5 (Cont'd)

	Initial Recoverable Reserves at 31/12/83	Cumulative Production to 31.12.82	Remaining Reserves	1983	1984	1985	1986	1987	1990	1995	2000	20005
	(Millions of Cubic Meters)			(Cubic Meters per Day)								
BP Exploration Canada Limited												
Chauvin Mannville A	1 250	0.999	0 251	75	75	71	63	55	39	21	11	0
Chauvin South Sparky A & B	1.550	0.940	0.610	180	180	169	150	133	93	51	28	0
Chauvin South Sparky E	0.795	0.347	0.448	115	140	131	115	101	68	35	18	0
Chauvin South Sparky H	0.710	0.357	0.353	115	140	129	107	90	52	21	0	0
Chauvin South Fld Other	1.003	0.439	0.564	147	185	182	164	145	101	55	0	0
David Lloydminster A	0.597	0.296	0.301	129	110	93	79	67	41	18	8	0
David Lloydminster C	0 360	0.048	0.312	77	130	119	98	81	46	18	0	0
Hayter Dina A (38%)	0.300	0.043	0.257	67	103	94	78	65	38	15	0	0
Hayter Dina B (38%)	0.179	0 033	0.146	42	57	53	44	37	22	9	0	0
Hayter Field Other (38%)	0.216	0.091	0.125	35	40	39	35	31	22	13	0	0
Miscellaneous & Undef	0 346	0.087	0.259	75	110	101	84	70	40	15	0	0
Pipeline Total	7.306	3.680	3.626	1058	1270	1184	1023	882	568	277	67	0
Husky Pipeline Ltd. and Manito Lloyd												
Hayter Dina A (62%)	0.489	0.070	0.419	110	167	153	128	107	62	25	1	0
Hayter Dina B (62%)	0.291	0.054	0.237	68	93	85	71	60	36	15	0	0
Hayter Field Other (62%)	0 353	0 149	0.204	57	65	63	56	50	36	21	0	0
Lindbergh Cumm RR&WW	0.680	0.086	0.594	210	230	213	179	151	91	38	0	0
Lindbergh Cummings XX&YY	0.589	0.027	0.562	97	210	196	169	146	94	45	0	0
Lindbergh Field Other	1.740	0.118	1.622	390	680	632	536	454	276	21	0	0
Lloydminster Sparky B	0.781	0.310	0.471	103	96	90	84	79	64	46	32	23
Lloyd Sparky C & GP A	1.400	1.004	0 396	120	150	139	120	103	65	31	0	0
Lloydminster Sparky G	0.845	0.322	0.523	170	195	180	154	131	81	36	0	0
LloydminsterSparky K	0.700	0 236	0.464	120	150	142	126	111	76	40	0	0
Lloyd Sparky & GP C&D	3.630	2.425	1.205	242	226	212	199	186	153	110	79	57
Lloydminster Field Other	2.433	1 371	1.062	222	263	245	228	212	171	119	83	0
Morgan Lloyd A	0.448	0 095	0.353	125	135	126	108	93	59	2	0	0
Viking Kinsella Wain B	4.550	2 785	1.765	741	635	545	467	400	252	117	16	0
Wainwright Wain & Spk A	12.000	7 781	4 219	1062	1140	1106	990	883	625	351	198	111
Wainwright Field Other	0 415	0.084	0 331	87	140	130	111	94	57	0	0	0
Wildmere Lloyd A & SPK E	3.000	0 912	2.088	400	470	470	449	406	300	181	109	65
Miscellaneous & Undef	1 850	0 935	0.915	272	308	279	243	211	138	68	34	0
Pipeline Total	36.194	18.764	17.430	4600	5356	5014	4425	3884	2643	1274	555	258
Truck and Tank – Heavy												
Glenevis Banff	1 630	1.143	0.487	107	101	96	91	86	74	57	43	0
Provost U Mann B	0.650	0.298	0.352	70	95	91	82	74	54	33	20	0
Miscellaneous & Undef	3 644	1 226	2.418	510	540	540	517	467	346	210	127	77
Pipeline Total	5.924	2.667	3.257	687	736	727	690	629	475	300	191	77
Heavy Undefined and Confidential												
Heavy Undef & Conf	0 625	0 000	0 625	85	169	157	142	129	95	58	35	21
Pipeline Total	0.625	0.000	0.625	85	169	157	142	129	95	58	35	21
Provincial Total	117.217	63.024	54.193	15433	17395	16192	14132	12277	8057	3899	1558	640

Table A7-5 (Cont'd)

	Initial Recoverable Reserves at 31/12/83	Cumulative Production to 31/12/82	Remaining Reserves	1983	1984	1985	1986	1987	1990	1995	2000	20005
	(Millions of Cubic Meters)			(Cubic Meters per Day)								
Saskatchewan												
Husky Pipeline Ltd. and Manito Pipelines Ltd.												
Aberfeldy Sparky SD Unit	6.700	4.465	2.235	600	619	586	525	470	338	195	112	0
Aberfeldy S Sparky SD Unit	1.556	1.354	0.202	81	92	84	68	55	30	0	0	0
Celtic Field Total	1.746	0.123	1.623	242	350	350	348	324	240	145	88	53
Dee Valley Waseco Non	0.475	0.175	0.300	95	100	93	81	71	47	23	0	0
Dulwich Sparky Sand Non	2.000	1.577	0.423	85	78	72	66	62	51	38	31	25
Epping Sparky & GP Non Unt	2.250	1.755	0.495	160	160	154	137	121	85	46	0	0
Epping South Sparky & GP Unt	2.800	2.306	0.494	167	146	128	113	100	71	43	28	0
Epping SW Sparky Unit	1.100	0.739	0.361	100	92	84	77	71	55	35	23	0
Golden Lk North Vol Unit	1.900	1.349	0.551	139	155	147	132	118	86	50	29	0
Golden Lk North Non Unit	0.590	0.355	0.235	75	80	76	67	58	39	19	0	0
Golden Lk S Sparky Non	1.000	0.454	0.546	175	174	158	139	122	82	43	22	0
Golden Lk S Waseca Non	2.100	1.174	0.926	280	320	298	258	223	144	70	0	0
Gully Lk Waseca Vol Unit	0.900	0.570	0.330	105	110	104	91	79	52	25	0	0
Gully Lk Waseca Non Unit	1.050	0.488	0.562	185	185	174	151	131	85	41	13	0
Lashburn Field Total	1.349	0.919	0.430	130	160	148	126	108	66	30	0	0
Macklin Sparky SD Non	0.450	0.230	0.220	105	105	94	74	59	29	0	0	0
Marsden S. Sparky Non	0.958	0.116	0.842	185	236	210	188	167	119	67	38	21
Northminster Field Total	1.182	0.784	0.398	101	90	80	72	65	50	34	24	18
Pikes Peak Waseca SD Non	1.900	0.166	1.734	460	560	542	471	406	258	122	57	0
Senlac Field Total	1.380	0.062	1.318	300	333	301	272	246	182	110	67	40
Standard Hill Waseca Non	1.540	0.602	0.938	280	252	226	204	183	134	79	46	27
Tangleflags GP Non	2.078	0.910	1.168	285	285	279	253	228	166	98	58	34
Tangleflags Lloyd SN Non	1.385	0.534	0.851	220	220	212	193	175	131	80	49	0
Tangleflags Other	2.224	1.020	1.204	400	400	380	333	291	195	100	0	0
Miscellaneous	13.062	6.524	6.538	2030	2243	1973	1698	1461	932	440	207	98
Pipeline Total	53.675	28.751	24.924	6989	7548	6965	6148	5405	3675	1944	900	320
Bow River and Cactus Lake												
Cactus Lake Bakken Non	2.370	0.444	1.926	593	569	524	462	407	279	148	79	38
Coleville Bakken SD Non	8.500	5.957	2.543	585	600	575	524	477	360	225	140	87
N.Hoosier Bakken SD Vol	1.137	0.734	0.403	110	110	105	94	83	59	33	18	10
N.Hoosier Blairmore Vol	0.700	0.498	0.202	65	65	60	53	46	31	15	4	0
Plover Lake Bakken Non	0.558	0.045	0.513	100	110	105	97	89	69	45	30	19
Miscellaneous	3.262	0.910	2.352	470	530	511	469	429	329	212	136	88
Pipeline Total	16.527	8.588	7.939	1923	1984	1884	1700	1534	1129	681	409	245
Bow River Pipeline Ltd												
Plato Total	0.620	0.275	0.345	77	115	108	96	85	59	32	0	0
Smiley Dewar Viking	4.600	3.860	0.740	207	210	200	181	164	121	73	0	0
Pipeline Total	5.220	4.135	1.085	285	325	309	278	249	181	106	0	0

Table A7-5 (Cont'd)

	Initial Recoverable Reserves at 31/12/83	Cumulative Production to 31/12/82	Remaining Reserves	1983	1984	1985	1986	1987	1990	1995	2000	20005
	(Millions of Cubic Meters)			(Cubic Meters per Day)								
South Saskatchewan Pipeline Company												
Battrum Unit No One	5.900	4.284	1.616	357	333	311	290	271	220	156	110	78
Battrum Unit No Two	1.820	1.034	0.786	175	210	202	182	163	117	67	39	22
Battrum Unit No Three	2.000	1.088	0.912	135	160	159	150	139	111	80	60	46
Battrum Unit No Four	1.082	0.741	0.341	105	103	93	82	73	51	28	15	0
Beverly Cantuar SD Non	0.500	0.321	0.179	71	63	55	49	43	29	16	0	0
Beverly U Rose. SD Unit	1.700	1.481	0.219	62	60	55	48	43	32	21	15	0
Bone Crk U Shaun. Unit	2.600	2.167	0.433	114	105	96	88	80	61	39	25	16
Butte U Shaun Vol Unit	1.320	0.633	0.687	102	97	92	88	84	72	57	44	34
Cantuar Cantuar Unit	4.300	3.490	0.810	270	260	240	210	183	123	63	26	0
Delta U.Shaun. Unit 1	2.400	2.065	0.335	81	74	68	63	58	46	32	24	10
Dollard U. Shaun Unit	13.087	12.123	0.964	390	390	354	290	237	130	47	2	0
Fosterton Main Unit	9.000	8.355	0.645	150	180	167	141	121	81	47	31	22
Gull Lake North Unit	3.215	2.867	0.348	111	100	89	80	71	51	29	17	0
Instow Unit	8.100	6.926	1.174	365	365	343	298	259	170	84	42	17
N. Premier Roseray Ttl	3.852	3.623	0.229	114	95	79	66	55	32	13	0	0
Rapdan Unit	2.924	2.272	0.652	190	220	204	176	151	96	45	21	0
South Success Unit	3.550	3.206	0.344	98	95	89	79	71	51	29	17	0
Suffield Field Total	3.800	2.707	1.093	335	335	314	274	239	158	79	40	20
Verlo Roseray SD Unit	2.250	1.232	1.018	240	238	220	199	181	136	84	52	32
Miscellaneous	15.808	12 009	3 799	1150	1200	1135	1007	893	623	342	0	0
Pipeline Total	**89.208**	**72.624**	**16.584**	**4620**	**4688**	**4374**	**3868**	**3424**	**2399**	**1368**	**586**	**300**
Westspur Pipeline Company												
Benson Midale Unit	1.950	1.347	0.603	111	108	103	97	91	76	57	42	31
Ingoldsby Frob Alida N U	1.684	1.414	0.270	80	80	75	67	59	41	22	12	0
Innes Frobisher Non Un	2.100	1.637	0.463	113	120	114	104	94	70	43	26	0
Lost Horse Hill Frob Ali	3.143	2.524	0.619	170	170	163	146	130	92	52	29	0
Midale Central Mid Unit	17.633	14.115	3.518	770	714	662	614	569	454	311	213	146
Midale Central Mid Non U	1.650	1.002	0.648	145	145	139	128	118	92	61	40	27
Oungre Rat. Vol. Unit 1	1.910	0.931	0.979	132	126	120	115	110	96	77	62	49
Viewfield Frob Alida Non	0.914	0.447	0.467	100	130	123	110	98	70	40	23	8
Weyburn Midale Unit	52.800	39.347	13.453	2024	1882	1754	1637	1531	1266	949	733	580
Weyburn Midale Non Unit	1.650	0.956	0.694	170	200	189	168	150	106	59	33	0
Miscellaneous	15.875	10.066	5.809	1287	1600	1510	1342	1192	837	464	257	142
Pipeline Total	**101.309**	**73.786**	**27.523**	**5104**	**5276**	**4958**	**4533**	**4149**	**3205**	**2139**	**1474**	**985**
Provincial Total	**265.939**	**187.884**	**78.055**	**18921**	**19822**	**18492**	**16529**	**14764**	**10592**	**6240**	**3371**	**1852**
Manitoba Canada												
Trans-Prairie Pipelines Ltd.												
Kirkella Total	**0.244**	**0.178**	**0.066**	**48**	**37**	**28**	**22**	**17**	**3**	**0**	**0**	**0**
Pipeline Total	**0.244**	**0.178**	**0.066**	**48**	**37**	**28**	**22**	**17**	**3**	**0**	**0**	**0**
Provincial Total	**0.244**	**0.178**	**0.066**	**48**	**37**	**28**	**22**	**17**	**3**	**0**	**0**	**0**
Canada Total	**383.400**	**251.086**	**132.314**	**34403**	**37255**	**34713**	**30683**	**27058**	**18653**	**10139**	**4930**	**2492**

Table A7-6
Annual Reserves Additions of Conventional Light Crude
NEB Projection

(Millions of Cubic Metres)

	Infill	Waterflood	Chemical	Miscible	Subtotal	Discoveries	Total
1983[1]	1.2	3.7	—	11.1	16.0	12.4	28.4
1984	1.0	3.0	—	21.3	25.3	16.5	41.8
1985	1.0	3.0	—	12.0	16.0	16.9	32.9
1986	1.0	3.0	—	8.0	12.0	16.2	28.2
1987	1.0	3.0	—	5.0	9.0	15.3	24.3
1988	.5	3.0	—	5.0	8.5	14.3	22.8
1989	.5	3.0	—	5.0	8.5	13.0	21.5
1990	.5	3.0	—	5.0	8.5	11.5	20.0
1991	—	3.0	—	5.0	8.0	10.9	18.9
1992	—	3.0	—	5.0	8.0	10.3	18.3
1993	—	3.0	—	5.0	8.0	9.3	17.3
1994	—	3.0	—	5.0	8.0	8.8	16.8
1995	—	3.0	—	5.0	8.0	8.0	16.0
1996	—	3.0	1.0	5.0	9.0	7.7	16.7
1997	—	3.0	1.0	5.0	9.0	7.4	16.4
1998	—	3.0	1.0	5.0	9.0	7.2	16.2
1999	—	3.0	1.0	5.0	9.0	6.8	15.8
2000	—	3.0	1.0	5.0	9.0	6.7	15.7
2001	—	2.0	1.0	5.0	8.0	6.6	14.6
2002	—	2.0	1.0	5.0	8.0	6.5	14.5
2003	—	2.0	1.0	5.0	8.0	6.4	14.4
2004	—	2.0	1.0	5.0	8.0	5.6	13.6
2005	—	2.0		5.0	7.0	5.0	12.0
Total	**6.7**	**64.7**	**9.0**	**147.4**	**227.8**	**229.3**	**457.1**

[1] Actual

Table A7-7
Productive Capacity from Reserves Additions of Conventional Light Crude NEB Projection

(Thousands of Cubic Metres Per Day)

	Infill	Waterflood	Chemical	Miscible	Subtotal	Discoveries	Total
1984	—	.1	—	—	.1	.4	.5
1985	.3	.5	—	—	.8	3.1	3.9
1986	.5	1.1	—	1.5	3.0	6.4	9.4
1987	.7	1.6	—	3.8	6.1	9.9	16.0
1988	.9	2.0	—	5.4	8.3	13.2	21.4
1989	1.0	2.4	—	6.5	9.9	15.9	25.8
1990	1.0	2.8	—	7.2	11.0	18.1	29.1
1991	1.0	3.1	—	7.7	11.9	19.6	31.5
1992	1.0	3.5	—	8.2	12.6	20.8	33.4
1993	.9	3.8	—	8.5	13.2	21.7	34.9
1994	.8	4.1	—	8.9	13.7	22.2	35.9
1995	.7	4.4	—	9.2	14.3	22.5	36.8
1996	.6	4.6	—	9.5	14.8	22.6	37.3
1997	.6	4.9	—	9.8	15.2	22.5	37.7
1998	.5	5.1	.1	10.0	15.7	22.3	38.0
1999	.5	5.3	.2	10.3	16.2	22.1	38.4
2000	.4	5.5	.4	10.5	16.8	21.8	38.6
2001	.4	5.7	.5	10.7	17.3	21.5	38.8
2002	.3	5.7	.7	10.9	17.6	21.2	38.8
2003	.3	5.7	.8	11.1	17.9	20.9	38.8
2004	.3	5.6	1.0	11.3	18.2	20.5	38.7
2005	.2	5.6	1.2	11.4	18.5	20.1	38.6

Table A7-8
Annual Reserves Additions of Conventional Heavy Crude
NEB Projection

(Millions of Cubic Metres)

	Waterflood	Lloydminster Thermal	Other Thermal	Subtotal	Discoveries	Total
1983(1)	2.5	—	—	2.5	14.9	17.4
1984	2.0	1.0	.1	3.1	5.5	8.6
1985	2.0	1.0	.1	3.1	5.6	8.7
1986	2.0	1.0	.1	3.1	5.4	8.5
1987	2.0	2.0	.2	4.2	5.1	9.3
1988	2.0	2.0	.2	4.2	4.8	9.0
1989	2.0	3.0	.3	5.3	4.3	9.6
1990	2.0	3.0	.4	5.4	3.8	9.2
1991	2.0	4.0	.5	6.5	3.6	10.1
1992	2.0	4.0	.6	6.6	3.4	10.0
1993	2.0	4.0	.7	6.7	3.1	9.8
1994	2.0	4.0	.8	6.8	2.9	9.7
1995	2.0	4.0	.9	6.9	2.7	9.6
1996	1.0	5.0	1.0	7.0	2.6	9.6
1997	1.0	5.0	1.0	7.0	2.5	9.5
1998	1.0	5.0	1.0	7.0	2.4	9.4
1999	1.0	5.0	1.0	7.0	2.3	9.3
2000	1.0	5.0	1.0	7.0	2.2	9.2
2001	—	6.0	1.0	7.0	2.2	9.2
2002	—	6.0	1.0	7.0	2.2	9.2
2003	—	6.0	1.0	7.0	2.1	9.1
2004	—	6.0	1.0	7.0	1.9	8.9
2005	—	6.0	1.0	7.0	1.7	8.7
Total	31.5	88.0	14.9	134.4	87.2	221.6

(1) Actual

Table A7-9
Productive Capacity from Reserves Additions of Conventional Heavy Crude
NEB Projection

(Thousands of Cubic Metres Per Day)

	Waterflood	Lloydminster Thermal	Other Thermal	Subtotal	Discoveries	Total
1984	—	.1	—	.2	.1	.3
1985	.4	.4	—	.8	1.0	1.8
1986	.7	.6	—	1.4	2.1	3.5
1987	1.0	1.0	.1	2.1	3.3	5.4
1988	1.3	1.4	.1	2.8	4.4	7.2
1989	1.6	2.0	.1	3.9	5.3	9.2
1990	1.9	2.6	.2	4.6	6.0	10.7
1991	2.1	3.3	.2	5.6	6.5	12.2
1992	2.3	4.1	.3	6.7	6.9	13.6
1993	2.5	4.8	.4	7.7	7.2	14.9
1994	2.7	5.4	.5	8.6	7.4	16.0
1995	2.9	5.9	.7	9.5	7.5	17.0
1996	3.1	6.6	.8	10.4	7.5	18.0
1997	3.1	7.3	1.0	11.3	7.5	18.8
1998	3.0	7.9	1.1	12.0	7.4	19.5
1999	3.0	8.5	1.3	12.8	7.4	20.1
2000	3.0	9.0	1.4	13.4	7.3	20.7
2001	3.0	9.6	1.5	14.1	7.2	21.3
2002	2.8	10.3	1.6	14.7	7.1	21.8
2003	2.6	10.9	1.7	15.2	7.0	22.2
2004	2.4	11.5	1.8	15.8	6.9	22.6
2005	2.3	12.0	1.9	16.2	6.7	22.9

Table A7-10
Ultimate Potential of Conventional Crude Oil In Conventional Producing Areas NEB Projection

(Millions of Cubic Metres)

Initial Established Reserves at 31 December 1982		
	– Light	2055
	– Heavy	366
	– Subtotal	2421
Potential Additions		
EOR in Light Established Pools		
	– Infill	10
	– Waterflood	75
	– Chemical	15
	– Miscible	304
	– Subtotal	404
EOR in Heavy Established Pools		
	– Infill and Waterflood	100
	– Lloydminster Area Thermal	216
	– Other Thermal	50
	– Chemical	15
	– Subtotal	381
	– EOR Subtotal	785
Other Appreciation and Discoveries		
	– Light	280
	– Heavy	140
	– Subtotal	420
Ultimate Potentials		
	– Light	2739
	– Heavy	887
	– Total	**3626**

Table A7-11
NEB Basic Assumptions for Converting Reserves Additions to Productive Capacity

	Delay[1]	Initial RLI[2]	Decline in RLI Percent[3]	Final RLI[4]
Light Crude				
Infill Drilling	0.5	10	0	10
Waterflood	0.5	15	0	15
Chemical	2.0	20	10	10
Miscible	2.0	20	10	15
Discoveries	0.5	15	15	10
Heavy Crude				
Waterflood	0.5	15	0	15
Lloydminster thermal	0.0	10	0	10
Other thermal	0.0	20	10	10
Discoveries	0.5	15	15	10

[1]The "Delay" is the time in years from discovery or project approval to first production.
[2]The "Initial RLI" is the reserves life index at the start of production.
[3]The "Decline in RLI" is the reserves life index expressed as a percentage.
[4]The "Final RLI" is the reserves life index during the declining production phase of the reservoir life.

Table A7-12
Active or Planned Light Oil Enhanced Recovery Projects

Pool	Operator
Ante Creek, BHL	Amoco
Bigoray, Nisku B	Amoco
Brazeau River, Nisku A, D, E	Petro-Canada
Caroline, Cardium E	Petro-Canada
Caroline, Viking A	Dome
Fenn Big Valley, D2A	Gulf
Joffre, Viking	Vikor
Judy Creek, BHL A & B	Esso
Kaybob South, Triassic A	Dome
Mitsue, Gilwood Unit #1	Chevron
Nipisi, Gilwood Unit #1	Amoco
Pembina, Nisku A	Chevron
Pembina, Nisku M	Getty
Pembina, Nisku G, K, O, P, N	Texaco
Rainbow, Keg River B	Canterra
Rainbow, Keg River IS-1	Canterra
Rainbow, Keg River IS-2	Canterra
Rainbow, Keg River IS-11	Mobil
Rainbow South, Keg River B	Amoco
Retlaw, Upper Mannville V	Westgrowth Petroleum
Snipe Lake, BHL	Gulf
Swan Hills, Unit #1	Home
Swan Hills South, BHL A	Amoco
West Pembina, Nisku A, C, D	Chevron
Willesden Green, Cardium A	Dome
Wizard Lake, D3A	Texaco

Table A7-13
Oil Sands Supply
NEB Projection

(Thousands of Cubic Metres per Day)

	Suncor	Syncrude	Other	Other	Bitumen[1]	Total
1983	8.5	15.0	—	—	4.0	27.5
1984	8.5	15.7	—	—	5.5	29.7
1985	8.5	16.5	—	—	7.0	32.0
1986	8.5	16.5	—	—	9.0	34.0
1987	8.5	16.5	—	—	11.0	36.0
1988	8.5	20.0	—	—	13.0	41.5
1989	8.5	20.0	—	—	15.0	43.5
1990	8.5	20.0	—	—	17.0	45.5
1991	8.5	20.0	—	—	19.0	47.5
1992	8.5	20.0	5	—	21.0	54.5
1993	8.5	20.0	10	—	23.0	61.5
1994	8.5	20.0	10	—	24.0	62.5
1995	8.5	20.0	10	—	25.0	63.5
1996	8.5	20.0	10	—	26.0	64.5
1997	8.5	20.0	10	—	27.0	65.5
1998	8.5	20.0	10	—	28.0	66.5
1999	8.5	20.0	10	5	29.0	72.5
2000	8.5	20.0	10	10	30.0	78.5
2001	8.5	20.0	10	10	31.0	79.5
2002	8.5	20.0	10	10	32.0	80.5
2003	8.5	20.0	10	10	33.0	81.5
2004	8.5	20.0	10	10	34.0	82.5
2005	8.5	20.0	10	10	35.0	83.5

[1] Includes experimental.

Table A7-14
Productive Capacity of Crude Oil and Equivalent Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
B.C.	6.1	6.1	6.2	6.1	6.0	5.4	5.6	6.1	5.9
AERCB	207.1	202.4	194.5	189.1	184.6	172.0	193.5	199.7	211.4
EUPC (Alberta only)	189.0	187.0	185.0	181.0	177.0	165.0	150.0	140.0	126.0
Saskatchewan	26.0	27.0	27.8	28.7	28.8	29.3	29.2	26.6	23.6
Provincial Totals	239.2	235.5	228.5	223.9	219.4	206.7	228.4	232.4	240.9
Amoco – Base Case	245.4	242.5	235.0	228.2	236.3	246.5	253.1	244.8	233.4
Amoco – Improvement	245.4	247.7	243.7	243.2	251.4	270.4	276.5	265.0	249.5
CPA	241.0	235.0	230.0	224.0	215.0	206.0	187.0	—	—
Dome – Low Price/Current Fiscal Regime	233.1	215.8	203.4	193.8	183.0	152.4	170.3	155.6	141.8
Dome – Low Price/Alternate Fiscal Regime	233.1	220.7	212.8	205.6	196.6	183.4	252.1	280.2	268.8
Dome – High Price/Current Fiscal Regime	233.1	224.4	218.1	212.6	207.5	211.9	297.0	387.7	374.5
Dome – High Price/Alternate Fiscal Regime	233.2	226.2	221.9	219.2	216.7	232.9	364.7	474.4	464.6
Gulf	221.0	219.4	213.0	211.4	208.1	216.2	244.7	260.7	—
Imperial	231.9	227.9	221.2	214.0	206.0	191.9	252.3	289.6	—
Petro-Canada – Low Case	245.0	244.0	247.0	242.0	233.0	207.0	169.0	140.0	115.0
Petro-Canada – High Case	245.0	244.0	248.0	246.0	240.0	231.0	251.0	235.0	209.0
Shell	—	229.4	211.4	197.7	184.3	151.2	142.0	181.5	—
Texaco – Base Case	232.2	221.1	211.0	204.3	197.6	193.2	197.9	—	—
Texaco – Opportunity Case	232.2	223.9	219.2	211.8	205.6	220.1	248.9	—	—
NEB	241.5	249.4	240.9	228.6	220.6	201.0	228.5	222.9	216.6

Table A7-15
Productive Capacity of Light Crude Oil
Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
B.C.	5.7	5.7	5.8	5.7	5.6	5.0	5.2	5.7	5.5
AERCB	174.0	169.0	159.0	149.0	143.0	140.0	147.0	158.0	175.0
EUPC (Alberta only)	158.0	156.0	154.0	150.0	147.0	136.0	119.0	106.0	94.0
Saskatchewan	7.6	8.4	8.9	9.0	8.8	8.1	7.6	7.0	5.8
Provincial Totals	187.3	183.1	173.7	163.7	157.4	153.1	159.8	170.7	186.3
Amoco – Base Case	193.2	185.5	172.4	161.8	162.4	163.3	158.0	135.7	111.3
Amoco – Improvement Case	193.2	189.1	179.3	172.9	173.3	182.0	175.1	148.5	118.8
CPA	183.0	184.0	177.0	168.0	157.0	142.0	126.0	—	—
Dome – Low Price/Current Fiscal Regime	179.5	163.6	153.1	144.7	135.3	111.5	134.7	127.1	117.3
Dome – Low Price/Alternate Fiscal Regime	179.6	168.1	160.6	152.2	143.5	130.7	199.3	232.0	223.9
Dome – High Price/Current Fiscal Regime	179.6	169.4	161.9	154.8	148.2	148.0	226.3	319.6	310.3
Dome – High Price/Alternate Fiscal Regime	179.6	170.4	163.6	157.3	151.9	158.4	273.3	380.7	374.6
Imperial	181.6	174.2	165.4	153.6	140.6	120.7	191.1	234.9	—
Petro-Canada – Low Case	193.0	188.0	186.0	181.0	172.0	159.0	129.0	103.0	83.0
Petro-Canada – High Case	193.0	188.0	187.0	182.0	175.0	169.0	194.7	186.5	170.1
Shell	—	176.8	160.9	148.5	136.1	106.1	93.6	121.5	—
Texaco – Base Case	176.0	163.3	149.0	140.7	131.1	135.2	140.6	—	—
Texaco – Opportunity Case	176.0	166.1	157.2	148.2	139.1	162.1	191.6	—	—
NEB	188.6	191.9	182.0	169.5	159.5	153.5	179.2	173.2	162.6

Table A7-16
Productive Capacity of Heavy Crude Oil
Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
AERCB	19.0	20.0	22.0	27.0	29.0	19.0	33.0	31.0	29.0
EUPC (Alberta only)	16.0	15.0	15.0	15.0	15.0	15.0	17.0	20.0	20.0
Saskatchewan	18.4	18.6	18.9	19.7	20.0	21.2	21.7	19.6	17.8
Provincial Totals	37.4	38.6	40.9	46.7	49.0	40.2	54.7	50.6	46.8
Amoco – Base Case	38.2	43.6	49.0	52.0	59.1	68.2	79.7	91.1	102.6
Amoco – Improvement Case	38.2	45.2	50.8	55.9	63.3	73.4	86.0	98.5	111.2
CPA	36.0	38.0	38.0	42.0	44.0	50.0	51.0	—	—
Dome – Low Price/Current Fiscal Regime	37.5	35.2	32.8	31.1	29.5	24.3	18.3	13.9	12.2
Dome – Low Price/Alternate Fiscal Regime	37.5	35.7	34.7	35.1	34.9	36.1	35.5	33.6	32.7
Dome – High Price/Current Fiscal Regime	37.5	38.1	38.8	39.8	41.2	47.9	54.3	51.9	50.6
Dome – High Price/Alternate Fiscal Regime	37.5	38.9	40.9	43.9	46.8	58.5	74.9	77.5	76.5
Imperial	35.1	38.5	40.6	44.9	48.8	54.3	44.4	38.6	—
Petro-Canada – Low Case	37.0	40.0	45.0	45.0	44.0	33.0	27.0	25.0	24.0
Petro-Canada – High Case	37.0	40.0	45.0	47.0	49.0	44.0	42.0	35.0	30.0
Shell	—	37.6	36.2	35.6	35.0	33.1	37.2	47.4	—
Texaco – Base Case and Opportunity Case	41.3	42.9	46.1	47.7	51.7	47.7	47.7	—	—
NEB	38.4	43.1	43.5	43.2	43.5	30.4	35.1	38.6	43.5

Table A7-17
Productive Capacity from Established Reserves of Light Crude Oil Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
B.C.	5.5	5.1	4.9	4.5	4.0	2.9	1.8	1.1	.7
AERCB	149.0	140.0	125.0	109.0	96.0	66.0	39.0	24.0	16.0
EUPC (Alberta only)	125.0	116.0	108.0	95.0	83.0	56.0	32.0	25.0	19.0
Saskatchewan	6.9	6.3	5.9	5.3	4.9	3.7	2.4	1.4	.9
Provincial Totals	161.4	151.5	135.8	118.8	104.9	72.6	43.2	26.5	17.6
Amoco – Base Case	158.3	147.5	129.7	114.6	102.5	71.9	42.0	24.8	14.6
Amoco – Improvement Case	158.3	150.5	134.7	119.6	107.5	79.9	47.0	29.8	19.6
CPA	156.3	155.6	145.4	132.0	117.5	82.1	48.0	—	—
Dome – Low Price/Current Fiscal Regime	152.3	133.9	118.9	106.2	94.8	66.6	39.8	25.4	14.9
Dome – Low Price/Alternate Fiscal Regime	152.3	136.9	123.1	110.8	99.7	72.4	43.3	27.6	16.2
Dome – High Price/Current Fiscal Regime and Alternate Fiscal Regime	152.3	138.4	125.9	114.6	104.2	78.2	46.8	29.8	17.5
Imperial	155.8	148.5	139.0	123.9	108.7	76.7	45.7	28.6	—
Petro-Canada – Low Case and – High Case	168.0	160.0	152.0	140.0	126.0	92.0	54.0	32.0	19.0
Shell	–	147.7	129.4	114.3	100.0	63.7	38.0	24.2	—
NEB	165.1	167.2	153.1	135.1	118.5	80.0	44.9	27.1	16.5

Table A7-18
Productive Capacity from Established Reserves of Heavy Crude Oil Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
AERCB(1)	16.0	14.0	13.0	11.0	10.0	6.0	3.0	1.0	—
EUPC (Alberta only)	13.0	11.0	9.0	8.0	7.0	4.0	2.0	1.0	—
Saskatchewan	17.6	16.3	14.7	13.5	12.1	9.1	5.4	2.9	1.6
Provincial Totals	**33.6**	**30.3**	**27.7**	**24.5**	**22.1**	**15.1**	**8.4**	**3.9**	**1.6**
CPA	31.1	29.6	27.2	24.8	22.4	16.5	9.5	—	—
Imperial	31.2	31.3	29.6	27.5	25.3	18.8	9.6	4.3	—
Husky/NOVA(2)	11.3	10.5	10.1	10.1	9.7	7.0	2.8	1.5	1.0
Petro-Canada – High Case	33.0	32.0	30.0	26.0	23.0	16.0	9.0	5.0	3.0
Shell	—	32.8	29.0	25.9	23.2	16.4	8.4	4.4	—
NEB	34.4	37.3	34.7	30.7	27.1	18.7	10.1	4.9	2.5

(1) Includes experimental.
(2) Lloydminster area only.

Table A7-19
Productive Capacity from Future Appreciation and New Discoveries of Conventional Light Crude Oil Excluding Appreciation of Currently Established Reserves Through Enhanced Recovery
Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
B.C.	.1	.4	.8	1.2	1.6	2.1	2.6	2.3	2.6
AERCB	—	3.0	6.0	8.0	11.0	16.0	19.0	18.0	16.0
EUPC (Alberta only)	10.0	13.0	14.0	17.0	20.0	29.0	29.0	24.0	19.0
Saskatchewan	.7	2.0	2.9	3.4	3.6	3.6	3.3	2.7	2.1
Provincial Totals	.7	5.4	9.7	12.6	16.2	21.7	24.9	23.1	20.7
Amoco – Base Case	3.1	6.2	9.3	10.1	15.5	22.6	27.0	27.9	28.2
Amoco – Improvement Case	3.1	6.8	11.2	16.3	21.4	32.6	35.6	31.1	27.8
Dome – Low Price/Current Fiscal Regime	.2	.7	1.2	3.1	4.3	6.9	9.0	10.1	9.2
Dome – Low Price/Alternate Fiscal Regime	.3	.8	2.7	4.0	5.3	10.2	14.8	17.0	16.8
Dome – High Price/Current Fiscal Regime	.3	.8	2.7	4.0	5.3	10.4	17.9	23.6	26.8
Dome – High Price/Alternate Fiscal Regime	.4	1.1	3.4	5.4	7.4	17.6	34.2	46.8	53.8
Imperial	—	.4	1.2	2.4	4.1	10.0	19.7	25.6	—
Petro-Canada – Low Case	1.0	2.6	4.6	7.0	9.3	15.9	21.5	20.3	16.5
Petro-Canada – High Case	1.0	2.8	5.3	8.2	11.5	21.1	28.1	24.6	18.1
Shell	—	3.0	5.3	7.4	8.9	13.1	16.2	17.6	—
NEB	—	0.4	3.1	6.4	9.9	18.1	22.5	21.8	20.1

Table A7-20
Productive Capacity from Future Appreciation and New Discoveries of Conventional Heavy Crude Oil Excluding Appreciation of Currently Established Reserves Through Enhanced Recovery
Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
AERCB	—	1.0	1.0	2.0	2.0	3.0	3.0	3.0	2.0
EUPC (Alberta only)	2.0	3.0	3.0	4.0	4.0	4.0	4.0	4.0	4.0
Saskatchewan	.6	1.9	3.2	4.5	5.4	6.7	6.4	4.9	3.5
Provincial Totals	**.6**	**2.9**	**4.2**	**6.5**	**7.4**	**9.7**	**9.4**	**7.9**	**5.5**
Imperial	—	1.7	2.9	4.1	4.9	5.4	2.8	1.2	—
Husky/NOVA[1]	.8	1.4	2.1	2.7	3.3	4.1	2.2	.8	.1
Petro-Canada – Low Case	—	1.5	3.5	4.8	6.4	6.8	5.4	4.8	5.0
Petro-Canada – High Case	—	1.5	3.5	4.8	6.4	7.6	6.0	5.9	5.5
Shell	—	.6	1.2	1.7	2.3	3.6	4.3	4.6	—
NEB	—	.1	1.0	2.1	3.3	6.0	7.5	7.3	6.7

[1] Lloydminster area only.

Table A7-21
Productive Capacity from Appreciation of Currently Established Light Crude Oil Reserves Through Enhanced Recovery
Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
B.C.	.2	.1	.1	.1	—	—	0.9	2.2	2.2
AERCB	—	1.0	2.0	5.0	8.0	15.0	20.0	20.0	18.0
EUPC (Alberta only)	1.0	1.0	3.0	9.0	14.0	20.0	27.0	26.0	25.0
Saskatchewan	—	—	—	.2	.3	.7	1.9	2.8	2.9
Provincial Totals	.2	1.1	2.1	5.3	8.3	15.7	22.8	25.0	23.1
Amoco – Base Case	—	—	1.6	5.3	10.6	25.9	46.1	40.1	25.6
Amoco – Improvement Case	—	—	1.6	5.2	10.6	26.6	49.6	44.7	28.5
Dome – Low Price/Current Fiscal Regime	.8	2.3	5.9	7.7	8.1	7.1	5.8	4.5	4.0
Dome – Low Price/Alternate Fiscal Regime	.8	3.6	7.5	9.6	10.3	10.8	9.8	8.5	6.7
Dome – High Price/Current Fiscal Regime	.8	3.4	6.1	8.6	10.5	16.6	23.6	24.1	23.3
Dome – High Price/Alternate Fiscal Regime	.8	4.2	7.1	9.7	12.1	19.8	34.8	37.4	35.8
Imperial	—	.1	.2	.5	1.0	3.5	9.3	11.9	—
Petro-Canada – Low Case	.3	1.4	4.5	7.5	9.6	12.6	15.3	12.5	9.0
Petro-Canada – High Case	.3	1.4	4.7	8.1	10.0	15.8	23.4	23.3	18.9
Shell	—	.1	.2	.3	.7	2.3	12.4	27.7	
NEB	—	.1	.8	3.0	6.1	11.0	14.3	16.8	18.5

Table A7-22
Productive Capacity from Appreciation of Currently Established Heavy Crude Oil Reserves Through Enhanced Recovery Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
AERCB	—	—	—	1.0	1.0	3.0	6.0	7.0	8.0
Saskatchewan	.2	.5	.9	1.8	2.6	5.4	9.8	11.8	12.7
Provincial Totals	**.2**	**.5**	**.9**	**2.8**	**3.6**	**8.4**	**15.8**	**18.8**	**20.7**
Imperial	—	—	.6	1.0	1.5	3.0	4.5	4.1	—
Husky/NOVA(1)	—	.1	.5	1.0	1.5	2.4	5.2	6.4	6.7
Petro-Canada – Low Case	—	1.5	3.5	3.9	4.6	5.7	7.0	7.6	8.3
Petro-Canada – High Case	—	1.5	3.5	5.2	7.6	11.4	14.0	15.1	16.5
Shell	—	—	—	.6	.6	1.0	2.0	5.0	—
NEB	—	.2	.8	1.4	2.1	4.6	9.5	13.4	16.2

(1) Lloydminster area only.

Table A7-23
Productive Capacity from Frontier Operations Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
Dome – Low Price/Current Fiscal Regime	—	—	—	—	—	—	49.1	56.1	58.2
Dome – Low Price/Alternate Fiscal Regime	—	—	—	—	—	6.4	78.7	125.6	130.9
Dome – High Price/Current Fiscal Regime & Alternate Fiscal Regime	—	—	—	—	—	11.8	95.9	187.1	187.1
Gulf	—	—	—	—	—	11.1	42.9	74.7	—
Imperial	—	—	—	—	—	.8	70.7	123.1	—
Petro-Canada – High Case	—	—	—	—	—	—	34.7	35.5	36.1
Shell	—	—	—	—	—	—	—	25.0	—
Texaco – Base Case and Opportunity Case	—	—	—	—	—	—	26.2	—	—
NEB	—	—	—	—	—	1.9	44.0	44.0	44.0

Table A7-24
Productive Capacity of Synthetic Oil Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
AERCB	25.0	25.0	26.0	27.0	28.0	43.0	69.0	96.0	125.0
EUPC (Alberta only)	23.0	26.0	29.0	29.0	30.0	31.0	31.0	31.0	31.0
Provincial Totals	25.0	25.0	26.0	27.0	28.0	43.0	69.0	96.0	125.0
Amoco – Base Case and Improvement Case	31.8	31.8	31.8	31.8	33.8	42.9	42.9	42.9	42.9
CPA	24.9	24.8	25.3	27.0	27.6	38.0	38.0	—	—
Dome – Low Price/Current Fiscal Regime	26.2	26.7	27.2	27.7	28.1	30.9	31.0	31.0	31.0
Dome – Low Price/Alternate Fiscal Regime	26.2	26.7	27.2	27.8	28.1	30.9	52.7	53.3	53.3
Dome – High Price/Current Fiscal Regime	26.2	26.7	27.2	27.7	28.1	30.9	42.1	55.0	55.6
Dome – High Price/Alternate Fiscal Regime	26.2	26.7	27.2	27.7	28.1	30.9	61.6	79.5	80.3
Gulf	27.0	27.0	27.0	27.0	28.6	30.2	39.7	44.5	—
Imperial	25.8	25.2	25.0	26.8	26.8	29.7	45.7	45.7	—
Petro-Canada – Low Case	24.0	24.0	25.0	26.0	27.0	38.0	38.0	38.0	38.0
Petro-Canada – High Case	24.0	24.0	25.0	26.0	27.0	40.0	54.0	71.0	78.0
Shell	—	26.0	26.0	26.5	26.5	27.0	27.0	27.0	27.0
Texaco – Base Case	25.0	25.0	25.0	25.4	25.4	34.0	34.0	—	—
Texaco – Opportunity Case	25.0	25.0	26.0	27.0	27.8	49.9	76.2	—	—
NEB	23.5	24.2	25.0	25.0	25.0	42.5	53.5	63.5	63.5

Table A7-25
Productive Capacity of Crude Bitumen From Oil Sands Mining and in Situ Operations Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
AERCB	28.0	30.2	34.0	40.0	44.0	50.0	90.0	116.0	144.0
CPA	28.6	29.8	31.6	37.9	40.7	57.6	60.1	—	—
Dome – Low Price Current Fiscal Regime	29.5	30.0	30.5	31.0	31.4	34.2	34.3	34.3	34.3
Dome – Low Price/Alternate Fiscal Regime	29.5	30.5	32.0	34.6	36.1	42.6	67.0	67.6	67.6
Dome – High Price/Current Fiscal Regime	29.5	31.7	34.4	37.0	39.8	51.6	71.9	84.8	85.4
Dome – High Price/Alternate Fiscal Regime	29.5	31.7	34.4	38.2	41.8	56.1	104.1	126.2	127.2
Gulf	27.0	31.8	33.4	36.5	38.1	42.9	52.4	57.2	—
Imperial	29.7	30.7	32.5	39.1	43.9	56.8	73.2	74.7	—
Husky/NOVA	27.4	30.4	32.4	37.0	39.3	46.3	58.3	72.7	90.1
Petro-Canada – High Case	28.0	29.0	33.0	37.0	39.0	49.0	67.0	80.0	83.0
Shell	—	30.3	32.0	33.9	35.4	39.1	49.5	60.4	—
NEB[1]	27.5	29.7	32.0	34.0	36.0	45.5	63.5	78.5	83.5

[1] Includes experimental.

Table A7-26
Productive Capacity of Pentanes Plus
Comparison of Submittors' Views
(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
AERCB	14.1	13.4	13.5	13.1	12.6	13.0	13.5	10.7	7.4
EUPC	15.0	16.0	16.0	16.0	15.0	14.0	14.0	14.0	12.0
Amoco – Base Case and Improvement Case	14.0	13.4	13.6	14.4	14.8	15.0	15.4	18.0	19.5
CPA	14.0	13.0	14.0	14.0	14.0	14.0	10.0	–	–
Dome – Low Price/Current & Alternate Fiscal Regime	16.0	16.9	17.5	18.1	18.2	16.6	17.3	14.6	12.3
Dome – High Price/Current & Alternate Fiscal Regime	16.0	16.9	17.5	18.0	18.1	16.0	16.5	16.2	13.5
Gulf	14.3	14.3	12.7	12.7	11.1	9.5	7.9	6.4	–
Imperial	15.2	15.2	15.2	15.5	16.6	16.9	16.8	16.1	–
Petro-Canada – Low Case	15.0	16.0	16.0	17.0	17.0	16.0	13.0	12.0	8.0
Petro-Canada – High Case[1]	15.0	16.0	16.0	17.0	17.0	17.8	14.9	13.5	8.9
Shell	–	15.0	14.3	13.6	13.2	12.0	11.2	12.6	–
Texaco – Base Case and Opportunity Case	14.9	14.9	15.9	15.9	14.8	10.3	9.5	–	–
NEB	14.5	14.4	15.4	15.9	17.6	17.1	14.2	11.1	10.5

[1] Includes frontiers (Hibernia & Venture).

Table A7-27
Annual Reserves Additions
From Future Appreciation and New Discoveries of Conventional Light Crude Oil Excluding Appreciation of Currently Established Reserves Through Enhanced Recovery
Comparison of Submittors' Views

(Millions of Cubic Metres)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
B.C.	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	.9
AERCB	17.0	17.0	16.0	15.0	13.0	9.0	6.0	5.0	4.0
Saskatchewan	5.1	4.7	3.8	2.6	2.1	1.4	.9	.5	.2
Provincial Totals	23.3	22.9	21.0	18.8	16.3	11.6	8.1	6.7	5.1
Amoco – Base Case	18.0	18.0	18.0	18.0	18.0	12.0	10.0	10.0	10.0
Amoco – Improvement Case	18.0	22.0	26.0	30.0	30.0	18.0	8.0	8.0	8.0
CPA	8.0	9.0	9.0	9.0	9.0	9.0	9.0	—	—
Dome – Low Price/ Current Fiscal Regime	7.9	7.6	6.9	6.4	6.1	5.8	5.5	4.2	3.1
Dome – Low Price/ Alternate Fiscal Regime	8.6	8.3	9.0	10.4	10.7	10.2	9.7	8.1	7.0
Dome – High Price/ Current Fiscal Regime	8.3	8.3	9.4	10.2	10.9	13.1	14.5	14.5	14.5
Dome – High Price/ Alternate Fiscal Regime	9.9	9.9	13.1	17.4	21.8	26.1	29.6	29.6	29.6
Imperial	12.4	11.4	11.1	12.1	12.4	12.7	11.8	10.0	—
Petro-Canada – Low Case	15.9	15.1	15.1	15.1	15.1	12.2	7.2	4.3	2.5
Petro-Canada – High Case	15.9	17.4	19.2	21.2	22.8	16.5	7.3	3.2	1.4
Shell	3.9	5.2	6.2	7.1	7.7	7.6	5.7	4.4	—
NEB	12.4	16.5	16.9	16.2	15.3	11.5	8.0	6.7	5.0

Table A7-28
Annual Reserves Additions
From Future Appreciation and New Discoveries of Conventional Heavy Crude Oil Excluding Appreciation of Currently Established Reserves Through Enhanced Recovery
Comparison of Submittors' Views

(Millions of Cubic Metres)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
AERCB	2.0	2.0	2.0	2.0	2.0	1.0	1.0	1.0	1.0
Saskatchewan	5.8	6.6	6.6	5.7	4.8	3.2	1.4	.6	.3
Provincial Totals	7.8	8.6	8.6	7.7	6.8	4.2	2.4	1.6	1.3
CPA	7.0	7.0	7.0	7.0	7.0	7.0	7.0	—	—
Imperial	3.6	3.3	2.7	2.3	1.8	1.1	.4	.2	—
Shell	1.4	1.8	2.0	2.1	2.1	1.7	1.1	.8	—
NEB	14.9	5.5	5.6	5.4	5.1	3.8	2.7	2.2	1.7

Table A7-29
Annual Reserves Additions From Appreciation of Currently Established Light Crude Oil Reserves Through Enhanced Recovery Comparison of Submittors' Views

(Millions of Cubic Metres)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
B.C.	.7	.7	.7	.7	.7	.7	.7	.6	.6
AERCB	17.0	20.0	25.0	27.0	25.0	15.0	8.0	5.0	4.0
Saskatchewan	—	—	.3	1.3	.3	.5	1.0	1.0	1.0
Provincial Totals	17.7	20.7	26.0	29.0	26.0	16.2	9.7	6.6	5.6
Amoco – Base Case and Improved Case	—	48.6	72.5	56.3	20.8	41.6	11.0	—	—
CPA	8.0	5.9	27.5	19.1	25.0	23.8	26.7	—	—
Dome – Low Price/ Current Fiscal Regime	3.2	3.0	2.7	2.5	2.4	2.3	2.2	1.6	1.3
Dome – Low Price/ Alternate Fiscal Regime	3.4	3.3	3.7	4.2	4.2	4.1	3.9	3.3	2.7
Dome – High Price/ Current Fiscal Regime	3.3	3.3	3.8	4.0	4.3	5.2	5.8	5.8	5.8
Dome – High Price/ Alternate Fiscal Regime	4.0	4.0	5.2	7.0	8.7	10.4	11.8	11.8	11.8
Imperial	6.0	3.0	19.0	4.2	11.9	10.3	—	—	—
Petro-Canada – Low Case	6.5	7.0	22.0	25.0	9.0	9.0	4.0	2.0	—
Petro-Canada – High Case	6.5	8.5	25.0	27.0	12.0	14.0	9.0	5.0	—
NEB	16.0	25.3	16.0	12.0	9.0	8.5	8.0	9.0	7.0

Table A7-30
Annual Reserves Additions From Appreciation of Currently Established Heavy Crude Oil Reserves Through Enhanced Recovery Comparison of Submittors' Views

(Millions of Cubic Metres)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
AERCB	—	—	1.0	1.0	2.0	2.0	3.0	3.0	3.0
Saskatchewan	.9	.9	2.2	3.4	2.7	3.5	4.3	4.7	4.7
Provincial Totals	.9	.9	3.2	4.4	4.7	5.5	7.3	7.7	7.7
CPA	—	—	—	5.2	8.6	9.0	1.0	—	—
Imperial	—	—	2.1	2.3	2.4	2.7	2.3	1.2	—
NEB	2.5	3.1	3.1	3.1	4.2	5.4	6.9	7.0	7.0

Table A7-31
Historical Data – Primary Demand for Oil – Canada

(Petajoules)

	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970
Residential	N/A	N/A	474.3	503.4	527.7	524.7	515.8	540.3	568.4	586.7	618.7
Commercial	N/A	N/A	122.7	162.0	168.1	193.9	222.4	247.9	284.4	293.8	308.6
Other Industrial	N/A	N/A	257.6	245.9	282.9	338.1	354.8	393.5	408.2	447.9	477.4
Transportation	N/A	N/A	823.4	867.8	917.6	975.6	1038.6	1096.3	1157.6	1200.1	1265.6
Non Energy	N/A	N/A	123.7	138.6	161.2	170.6	185.1	188.7	193.7	211.3	252.7
Total End Use	**N/A**	**N/A**	**1801.7**	**1917.7**	**2057.4**	**2202.9**	**2316.8**	**2466.7**	**2612.3**	**2739.8**	**2923.0**
Own Use	N/A	N/A	149.8	157.5	154.9	162.0	167.9	175.2	182.8	186.1	201.1
Electricity Generation	N/A	N/A	16.9	18.1	25.5	35.8	39.6	56.3	82.0	79.5	110.1
Steam Production	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Refinery LPG	N/A	N/A	0.1	0.2	0.8	1.3	2.0	20.9	18.8	20.3	24.2
Total Primary	**N/A**	**N/A**	**1968.5**	**2093.5**	**2238.6**	**2402.0**	**2526.2**	**2719.1**	**2895.9**	**3025.7**	**3258.4**

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
Residential	614.4	646.1	610.0	641.4	612.4	600.5	541.3	523.4	513.1	492.4	401.8
Commercial	306.9	326.8	286.2	272.7	212.6	261.5	228.8	245.5	216.0	208.1	194.6
Other Industrial	477.3	503.5	542.0	553.9	539.4	528.6	560.1	530.7	545.6	509.4	452.5
Transportation	1313.5	1407.9	1535.9	1597.9	1622.8	1690.5	1736.4	1796.8	1922.2	1958.1	1908.1
Non Energy	256.3	281.4	321.2	318.3	302.5	310.3	350.1	379.4	421.6	387.5	379.6
Total End Use	**2968.3**	**3165.7**	**3295.3**	**3384.2**	**3289.7**	**3391.4**	**3416.7**	**3475.8**	**3618.5**	**3555.4**	**3336.5**
Own Use	212.9	225.4	247.4	249.1	249.4	237.8	259.8	277.2	280.3	267.8	249.9
Electricity Generation	112.9	113.1	116.3	122.0	125.2	145.5	139.2	148.8	139.4	132.1	97.7
Steam Production	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.0	12.4	9.6
Refinery LPG	24.6	28.1	27.3	29.4	37.4	52.5	57.3	59.1	66.8	61.9	57.5
Total Primary	**3318.7**	**3532.4**	**3686.3**	**3784.7**	**3701.7**	**3827.0**	**3872.9**	**3960.9**	**4117.1**	**4029.6**	**3751.2**

Table A7-32
Primary Demand for Oil – Canada
Comparison of Submittors' Views

(Petajoules)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
CPA	3403	N/A	N/A	N/A	N/A	N/A	3339	3370	N/A	N/A
Dome – Low	3274	3110	3112	3157	3182	3196	3287	3551	3801	N/A
Gulf	3265	3028	3005	3005	3021	3007	3048	3130	3244	N/A
Husky/NOVA(1)	3368	3167	3254	3295	3306	3324	3440	3641	3922	4214
Imperial	3322	3122	3052	2979	2923	2896	2780	2532	2369	N/A
Petro-Canada – Base	3251	3082	3148	3185	3184	3140	3041	2982	3073	N/A
Shell	3326	3132	3093	2997	2980	2953	2912	2918	2987	N/A
Texaco(1)	3427	3165	3150	3115	3080	3055	3055	3155	N/A	N/A
APMC	N/A	3105	2936	2838	2809	2782	2754	2838	2920	3006
NEB	3283	3044	3011	2965	2859	2830	2783	2735	2879	3001

(1) Includes Oil and LPG

Table A7-33
Total Petroleum Product Demand[1] – Canada and Regions NEB Projection

(Petajoules)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Canada										
Aviation Gasoline	6.0	6.0	5.7	5.7	5.6	5.6	5.4	5.2	5.0	5.0
Motor Gasoline	1188.1	1150.7	1132.8	1098.8	1063.6	1035.4	997.1	986.0	997.3	1003.7
Av. Turbo – Kerosene (Jet A)	95.3	95.9	93.3	93.3	93.8	96.5	101.0	124.2	147.1	158.9
– Naphtha (Jet B)	50.5	44.4	43.1	42.2	41.6	42.0	41.4	46.0	49.0	52.9
– Total	145.9	140.3	136.4	135.6	135.4	138.5	142.5	170.3	196.1	211.8
Light Fuel & Kerosene	452.2	366.7	350.7	318.0	295.7	277.4	218.6	165.5	147.7	140.2
Diesel Fuel Oil	528.7	544.2	552.4	559.8	567.0	575.3	605.6	665.3	747.4	809.8
Heavy Fuel Oil	487.9	375.6	371.8	366.7	330.8	351.3	355.6	260.3	271.8	286.4
Asphalt	108.3	112.0	114.4	116.9	119.4	121.8	129.2	141.6	153.9	166.3
Lubes and Greases	34.5	35.8	37.1	38.4	39.7	41.0	44.8	51.3	57.7	64.2
Petrochemical Feedstock	115.8	105.9	109.5	126.0	104.4	82.7	82.6	82.7	83.0	83.1
Other Products	214.8	206.0	205.8	204.7	201.1	200.0	200.8	205.9	218.6	229.6
Total Oil Products	3282.7	3043.6	3017.1	2971.2	2863.1	2829.0	2782.5	2734.4	2879.0	3000.5
Refinery LPG	61.0	51.9	53.6	53.3	53.7	54.8	55.5	57.9	61.2	64.6
Total Products + Ref. LPG	3343.8	3095.6	3070.7	3024.6	2916.8	2884.2	2838.1	2792.4	2940.2	3065.1
Atlantic Provinces										
Aviation Gasoline	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Motor Gasoline	99.7	95.0	99.4	96.4	93.7	91.7	88.9	88.4	90.1	94.7
Av. Turbo – Kerosene (Jet A)	8.3	7.8	7.9	7.8	7.8	7.9	8.0	9.2	10.2	11.1
– Naphtha (Jet B)	6.8	7.6	5.4	5.1	4.8	4.7	4.0	3.4	2.4	2.6
– Total	15.2	15.5	13.4	13.0	12.7	12.6	12.1	12.7	12.7	13.7
Light Fuel & Kerosene	84.5	72.0	72.8	69.5	66.3	64.8	59.8	47.5	39.4	39.7
Diesel Fuel Oil	53.6	50.7	51.8	54.3	54.2	54.4	57.3	61.5	71.5	82.8
Heavy Fuel Oil	138.4	94.5	122.3	136.6	111.6	135.0	140.5	46.1	45.6	43.1
Asphalt	8.5	9.7	9.9	10.0	10.2	10.3	10.8	11.6	12.5	13.3
Lubes and Greases	2.3	2.4	2.5	2.6	2.7	2.8	3.1	3.7	4.2	4.7
Petrochemical Feedstock	0.8	0.8	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0
Other Products	13.3	11.2	12.3	12.6	11.6	12.3	12.3	9.1	9.3	9.8
Total Oil Products	417.1	352.5	385.9	396.6	364.8	385.6	386.6	282.3	286.8	303.4
Refinery LPG	5.7	5.4	5.6	5.5	5.5	5.9	6.7	7.1	7.6	8.5
Total Products + Ref. LPG	422.8	357.9	391.5	402.1	370.4	391.6	393.3	289.4	294.5	312.0

[1] Includes own use, electricity generation and steam production

Table A7-33 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Quebec					
Aviation Gasoline	0.7	0.8	0.7	0.7	0.7	0.6	0.6	0.6	0.6	0.6
Motor Gasoline	245.6	235.2	231.9	219.2	210.1	203.0	193.9	195.8	202.7	192.8
Av. Turbo – Kerosene (Jet A)	21.3	21.0	20.3	20.0	19.8	20.1	20.2	22.9	25.0	27.0
– Naphtha (Jet B)	5.3	4.6	4.4	4.2	4.1	4.0	3.7	3.6	3.4	3.7
– Total	26.7	25.6	24.7	24.3	23.9	24.2	23.9	26.6	28.4	30.7
Light Fuel & Kerosene	166.4	137.0	128.1	113.7	104.9	97.1	72.9	57.3	55.1	50.4
Diesel Fuel Oil	84.8	82.0	81.5	83.6	85.5	84.1	90.8	99.8	112.2	128.0
Heavy Fuel Oil	182.1	139.3	120.7	106.4	101.8	100.8	100.6	100.5	101.0	109.4
Asphalt	24.1	25.1	25.7	26.2	26.8	27.4	29.0	31.8	34.5	37.3
Lubes and Greases	5.7	6.0	6.2	6.5	6.7	7.0	7.7	8.9	10.2	11.4
Petrochemical Feedstock	36.2	28.7	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Other Products	60.8	56.8	55.2	53.7	53.2	52.7	52.6	54.5	57.7	60.6
Total Oil Products	833.7	737.0	693.2	652.7	632.0	615.4	590.4	594.2	620.7	639.5
Refinery LPG	13.6	10.4	12.0	12.0	12.0	12.0	12.3	13.0	13.8	14.6
Total Products + Ref. LPG	847.3	747.4	705.3	664.8	644.0	627.5	602.7	607.3	634.6	654.2
					Ontario					
Aviation Gasoline	1.3	1.3	1.2	1.2	1.2	1.2	1.2	1.1	1.1	1.1
Motor Gasoline	415.3	407.0	394.4	387.3	374.3	364.1	352.1	354.9	356.4	339.0
Av. Turbo – Kerosene (Jet A)	35.9	36.6	35.8	36.1	36.7	38.0	40.9	52.4	64.6	69.8
– Naphtha (Jet B)	7.6	7.3	6.2	5.9	5.7	5.6	5.1	4.9	4.4	4.7
– Total	43.6	44.0	42.1	42.1	42.4	43.7	46.0	57.4	69.1	74.6
Light Fuel & Kerosene	140.2	109.7	101.3	90.7	83.3	76.3	53.7	38.9	33.5	31.4
Diesel Fuel Oil	125.7	137.6	141.4	143.7	145.3	151.4	160.3	175.4	191.8	199.7
Heavy Fuel Oil	95.4	92.8	85.5	80.1	78.3	77.1	74.9	70.4	75.4	78.8
Asphalt	29.7	31.5	32.1	32.8	33.5	34.2	36.3	39.7	43.2	46.6
Lubes and Greases	14.0	14.4	14.9	15.3	15.7	16.1	17.3	19.4	21.5	23.6
Petrochemical Feedstock	76.4	74.3	84.3	95.2	72.8	50.7	50.5	50.7	51.0	51.0
Other Products	79.9	78.6	78.4	78.5	76.5	75.1	75.0	78.2	82.6	85.1
Total Oil Products	1022.0	991.8	976.2	967.5	923.8	890.4	867.7	886.6	925.9	931.3
Refinery LPG	20.9	18.2	18.0	17.9	18.5	19.2	19.0	19.6	20.1	20.4
Total Products + Ref. LPG	1043.0	1010.0	994.2	985.5	942.3	909.6	886.8	906.2	946.1	951.8

Table A7-33 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Manitoba					
Aviation Gasoline	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Motor Gasoline	52.0	51.0	47.9	47.1	44.4	43.0	40.4	38.4	37.9	39.0
Av. Turbo – Kerosene (Jet A)	1.4	1.6	1.4	1.5	1.5	1.6	1.7	2.3	2.9	3.1
– Naphtha (Jet B)	5.3	4.2	4.7	4.7	4.7	4.8	5.0	6.0	6.8	7.4
– Total	6.8	5.9	6.2	6.2	6.2	6.4	6.7	8.3	9.8	10.5
Light Fuel & Kerosene	8.2	6.2	5.7	5.1	4.8	4.5	3.6	2.5	1.8	1.6
Diesel Fuel Oil	28.3	31.5	30.4	30.2	30.4	31.0	35.3	39.9	49.0	57.3
Heavy Fuel Oil	6.7	6.1	5.6	5.1	4.9	4.7	4.1	3.6	3.6	3.5
Asphalt	4.0	3.7	3.7	3.8	3.8	3.8	3.9	4.1	4.3	4.5
Lubes and Greases	1.2	1.3	1.3	1.3	1.4	1.4	1.5	1.7	1.9	2.0
Petrochemical Feedstock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Products	3.9	3.9	3.8	3.7	3.7	3.6	3.7	3.9	4.2	4.6
Total Oil Products	112.1	110.5	105.6	102.5	100.6	99.5	100.3	103.4	113.3	123.9
Refinery LPG	0.8	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6
Total Products + Ref. LPG	**113.0**	**111.1**	**106.1**	**103.0**	**101.1**	**100.0**	**100.8**	**104.0**	**113.9**	**124.6**
					Saskatchewan					
Aviation Gasoline	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Motor Gasoline	66.0	66.3	66.6	65.1	63.6	62.2	59.4	55.7	55.2	59.8
Av. Turbo – Kerosene (Jet A)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
– Naphtha (Jet B)	3.2	2.8	2.9	2.9	3.0	3.1	3.3	4.1	4.9	5.2
– Total	3.2	2.9	2.9	3.0	3.0	3.1	3.3	4.2	4.9	5.3
Light Fuel & Kerosene	12.4	8.9	8.4	7.5	7.0	6.6	5.3	4.1	4.1	3.6
Diesel Fuel Oil	39.8	43.3	48.1	49.3	49.6	50.1	51.6	56.3	64.6	72.4
Heavy Fuel Oil	5.1	3.6	3.0	3.1	3.1	3.1	3.1	3.5	3.7	3.9
Asphalt	7.6	6.4	6.4	6.5	6.5	6.6	6.8	7.1	7.4	7.7
Lubes and Greases	1.9	2.0	2.0	2.1	2.1	2.2	2.4	2.7	3.0	3.3
Petrochemical Feedstock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Products	7.8	7.8	8.0	8.1	8.1	8.1	8.3	8.7	9.4	10.2
Total Oil Products	144.7	141.8	146.2	145.2	143.8	142.7	140.9	143.0	153.1	167.0
Refinery LPG	2.4	2.2	2.3	2.3	2.2	2.2	2.2	2.3	2.4	2.7
Total Products + Ref. LPG	**147.1**	**144.0**	**148.5**	**147.5**	**146.1**	**145.0**	**143.2**	**145.3**	**155.6**	**169.7**

Table A7-33 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Alberta										
Aviation Gasoline	0.9	0.8	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8
Motor Gasoline	166.2	161.1	157.5	150.7	145.6	141.2	132.4	123.1	125.6	139.5
Av. Turbo – Kerosene (Jet A)	17.1	17.2	16.9	17.0	17.2	17.8	19.0	24.1	29.4	31.7
– Naphtha (Jet B)	10.0	8.2	8.7	8.7	8.7	8.9	9.1	10.8	12.2	13.2
– Total	27.1	25.5	25.7	25.8	26.0	26.8	28.2	35.0	41.6	45.0
Light Fuel & Kerosene	6.2	4.8	4.5	3.5	3.5	3.5	3.5	2.4	2.0	1.7
Diesel Fuel Oil	101.4	105.1	104.4	101.3	102.6	102.5	103.9	113.3	126.8	129.7
Heavy Fuel Oil	2.7	2.5	2.1	1.9	1.9	1.9	1.6	1.7	1.9	2.1
Asphalt	24.8	24.7	25.4	26.1	26.7	27.4	29.4	32.8	36.2	39.6
Lubes and Greases	5.0	5.3	5.5	5.7	5.9	6.1	6.8	7.8	8.9	10.0
Petrochemical Feedstock	0.0	0.1	4.3	9.9	10.6	11.0	11.0	11.0	11.0	11.0
Other Products	32.6	32.5	32.7	32.6	32.7	32.7	33.1	34.8	37.6	40.4
Total Oil Products	367.4	362.7	363.4	358.8	356.8	354.4	351.1	363.2	392.7	419.9
Refinery LPG	11.1	10.8	10.9	10.7	10.7	10.6	10.5	10.8	11.7	12.5
Total Products + Ref. LPG	378.6	373.6	374.3	369.5	367.5	365.0	361.7	374.1	404.5	432.5
British Columbia and Territories										
Aviation Gasoline	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Motor Gasoline	143.0	134.9	134.9	133.8	131.6	129.9	129.6	129.2	129.3	138.7
Av. Turbo – Kerosene (Jet A)	11.0	11.3	10.6	10.5	10.5	10.7	10.9	12.9	14.7	15.8
– Naphtha (Jet B)	11.9	9.4	10.4	10.4	10.4	10.6	10.9	13.0	14.7	15.8
– Total	22.9	20.7	21.1	21.0	20.9	21.4	21.9	25.9	29.4	31.7
Light Fuel & Kerosene	34.1	27.8	29.5	27.7	25.6	24.2	19.5	12.6	11.4	11.5
Diesel Fuel Oil	94.8	93.3	94.1	96.9	98.6	101.1	105.9	118.6	131.2	139.5
Heavy Fuel Oil	57.1	36.0	33.1	33.2	28.9	28.5	30.5	34.1	40.3	45.4
Asphalt	9.3	10.6	10.9	11.2	11.5	11.8	12.6	14.1	15.5	17.0
Lubes and Greases	4.0	4.2	4.5	4.7	4.9	5.1	5.7	6.7	7.8	8.8
Petrochemical Feedstock	2.1	1.8	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.0
Other Products	16.1	14.9	15.1	15.2	15.1	15.1	15.5	16.3	17.5	18.8
Total Oil Products	385.4	346.2	346.7	347.2	340.7	340.8	344.9	361.3	386.1	415.1
Refinery LPG	6.2	4.1	4.1	4.2	4.1	4.1	4.1	4.3	4.6	5.0
Total Products + Ref. LPG	391.7	350.4	350.9	351.4	344.8	344.9	349.1	365.7	390.8	420.1

Table A7-33 (Cont'd.)

(Thousands of Cubic Metres per Day)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Canada					
Aviation Gasoline	0.493	0.492	0.470	0.466	0.462	0.458	0.446	0.429	0.409	0.409
Motor Gasoline	93.921	90.921	89.548	86.863	84.076	81.851	78.817	77.940	78.834	79.343
Av. Turbo – Kerosene (Jet A)	7.273	7.313	7.121	7.118	7.154	7.360	7.705	9.476	11.220	12.117
– Naphtha (Jet B)	3.853	3.390	3.286	3.223	3.178	3.206	3.164	3.514	3.739	4.038
– Total	11.127	10.703	10.408	10.341	10.332	10.566	10.868	12.991	14.959	16.155
Light Fuel & Kerosene	32.118	26.045	24.907	22.590	21.001	19.705	15.525	11.752	10.483	9.951
Diesel Fuel Oil	37.453	38.550	39.130	39.658	40.161	40.751	42.898	47.125	52.941	57.360
Heavy Fuel Oil	32.035	24.663	24.412	24.081	21.722	23.066	23.348	17.092	17.851	18.808
Asphalt	6.678	6.902	7.054	7.206	7.358	7.510	7.967	8.727	9.488	10.249
Lubes and Greases	2.420	2.510	2.600	2.690	2.780	2.870	3.141	3.592	4.043	4.494
Petrochemical Feedstock	9.023	8.256	8.535	9.820	8.140	6.446	6.435	6.447	6.470	6.474
Other Products	14.289	13.732	13.728	13.669	13.435	13.370	13.433	13.784	14.636	15.379
Total Oil Products	239.557	222.813	220.792	217.385	209.467	206.593	202.877	199.879	210.115	218.621
Refinery LPG	6.171	5.250	5.417	5.394	5.432	5.537	5.614	5.858	6.185	6.533
Total Products + Ref. LPG	245.728	228.063	226.209	222.779	214.899	212.130	208.491	205.738	216.300	225.154
					Atlantic Provinces					
Aviation Gasoline	0.033	0.032	0.030	0.029	0.028	0.027	0.025	0.020	0.016	0.016
Motor Gasoline	7.888	7.510	7.859	7.624	7.413	7.249	7.033	6.993	7.123	7.488
Av. Turbo – Kerosene (Jet A)	0.635	0.602	0.608	0.601	0.597	0.607	0.613	0.709	0.785	0.848
– Naphtha (Jet B)	0.526	0.584	0.417	0.393	0.372	0.360	0.310	0.260	0.187	0.202
– Total	1.161	1.187	1.025	0.994	0.970	0.968	0.923	0.969	0.972	1.050
Light Fuel & Kerosene	6.001	5.113	5.171	4.932	4.709	4.600	4.245	3.373	2.802	2.818
Diesel Fuel Oil	3.798	3.593	3.672	3.851	3.845	3.859	4.063	4.363	5.065	5.869
Heavy Fuel Oil	9.090	6.207	8.034	8.968	7.332	8.866	9.227	3.029	3.000	2.835
Asphalt	0.527	0.600	0.610	0.620	0.630	0.640	0.671	0.721	0.771	0.822
Lubes and Greases	0.164	0.171	0.179	0.186	0.193	0.201	0.223	0.260	0.297	0.334
Petrochemical Feedstock	0.069	0.067	0.071	0.074	0.078	0.078	0.078	0.078	0.078	0.078
Other Products	0.878	0.740	0.809	0.831	0.767	0.810	0.813	0.604	0.616	0.651
Total Oil Products	29.608	25.219	27.459	28.109	25.965	27.297	27.301	20.410	20.740	21.962
Refinery LPG	0.581	0.550	0.566	0.561	0.562	0.601	0.678	0.720	0.775	0.865
Total Products + Ref. LPG	30.190	25.769	28.025	28.670	26.527	27.898	27.979	21.130	21.514	22.827

Table A7-33 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
					Quebec					
Aviation Gasoline	0.060	0.072	0.058	0.058	0.057	0.057	0.056	0.055	0.053	0.053
Motor Gasoline	19.422	18.592	18.334	17.333	16.611	16.054	15.334	15.482	16.023	15.242
Av. Turbo – Kerosene (Jet A)	1.629	1.601	1.552	1.530	1.517	1.538	1.541	1.753	1.907	2.059
– Naphtha (Jet B)	0.411	0.353	0.337	0.324	0.313	0.310	0.286	0.282	0.262	0.283
– Total	2.041	1.954	1.890	1.855	1.830	1.848	1.827	2.035	2.169	2.342
Light Fuel & Kerosene	11.806	9.727	9.096	8.071	7.444	6.897	5.173	4.065	3.910	3.574
Diesel Fuel Oil	6.010	5.814	5.778	5.923	6.060	5.963	6.432	7.070	7.949	9.067
Heavy Fuel Oil	11.962	9.148	7.928	6.990	6.688	6.619	6.605	6.600	6.633	7.188
Asphalt	1.490	1.553	1.587	1.621	1.655	1.688	1.790	1.960	2.129	2.299
Lubes and Greases	0.404	0.421	0.438	0.456	0.473	4.490	0.543	0.630	0.717	0.804
Petrochemical Feedstock	2.827	2.239	1.407	1.407	1.407	1.406	1.406	1.406	1.406	1.407
Other Products	4.014	3.754	3.657	3.563	3.526	3.499	3.491	3.622	3.832	4.024
Total Oil Products	60.035	53.276	50.172	47.275	45.751	44.522	42.657	42.923	44.821	45.999
Refinery LPG	1.375	1.055	1.219	1.222	1.217	1.218	1.245	1.321	1.399	1.480
Total Products + Ref. LPG	**61.410**	**54.331**	**51.392**	**48.496**	**46.968**	**45.740**	**43.901**	**44.244**	**46.220**	**47.479**
					Ontario					
Aviation Gasoline	0.111	0.114	0.106	0.105	0.104	0.102	0.099	0.095	0.090	0.090
Motor Gasoline	32.835	32.177	31.180	30.618	29.591	28.786	27.834	28.056	28.174	26.802
Av. Turbo – Kerosene (Jet A)	2.745	2.796	2.737	2.760	2.799	2.904	3.121	4.002	4.932	5.327
– Naphtha (Jet B)	0.585	0.559	0.477	0.456	0.439	0.432	0.394	0.377	0.336	0.363
– Total	3.330	3.335	3.213	3.216	3.238	3.336	3.514	4.379	5.269	5.690
Light Fuel & Kerosene	9.951	7.788	7.192	6.440	5.912	5.421	3.813	2.766	2.380	2.230
Diesel Fuel Oil	8.908	9.753	10.016	10.182	10.296	10.727	11.358	12.428	13.591	14.150
Heavy Fuel Oil	6.264	6.093	5.617	5.265	5.143	5.066	4.921	4.626	4.952	5.177
Asphalt	1.832	1.942	1.984	2.027	2.069	2.111	2.239	2.451	2.663	2.875
Lubes and Greases	0.985	1.014	1.043	1.072	1.101	1.130	1.217	1.362	1.508	1.653
Petrochemical Feedstock	5.955	5.795	6.574	7.418	5.678	3.952	3.938	3.950	3.973	3.976
Other Products	5.368	5.294	5.289	5.299	5.170	5.077	5.079	5.298	5.601	5.772
Total Oil Products	75.538	73.325	72.213	71.642	68.301	65.708	64.013	65.412	68.201	68.416
Refinery LPG	2.120	1.840	1.819	1.815	1.873	1.947	1.925	1.985	2.038	2.068
Total Products + Ref. LPG	**77.659**	**75.165**	**74.032**	**73.457**	**70.174**	**67.655**	**65.938**	**67.397**	**70.239**	**70.484**

Table A7-33 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Manitoba										
Aviation Gasoline	0.058	0.061	0.055	0.055	0.055	0.054	0.053	0.051	0.049	0.049
Motor Gasoline	4.111	4.032	3.787	3.647	3.511	3.399	3.196	3.042	2.996	3.084
Av. Turbo – Kerosene (Jet A)	0.113	0.129	0.114	0.116	0.118	0.124	0.135	0.178	0.224	0.242
– Naphtha (Jet B)	0.409	0.326	0.361	0.360	0.361	0.370	0.383	0.459	0.523	0.565
– Total	0.522	0.455	0.475	0.476	0.480	0.494	0.518	0.637	0.748	0.808
Light Fuel & Kerosene	0.588	0.446	0.410	0.371	0.349	0.327	0.260	0.181	0.130	0.118
Diesel Fuel Oil	2.009	2.233	2.158	2.139	2.158	2.201	2.505	2.832	3.474	4.063
Heavy Fuel Oil	0.444	0.403	0.372	0.337	0.327	0.310	0.274	0.242	0.240	0.231
Asphalt	0.250	0.230	0.233	0.235	0.237	0.239	0.246	0.258	0.269	0.281
Lubes and Greases	0.090	0.092	0.095	0.097	0.100	0.102	0.109	0.121	0.133	0.146
Petrochemical Feedstock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Products	0.261	0.260	0.253	0.249	0.247	0.246	0.250	0.261	0.283	0.308
Total Oil Products	8.333	8.213	7.839	7.606	7.463	7.373	7.413	7.625	8.322	9.087
Refinery LPG	0.089	0.056	0.054	0.052	0.051	0.051	0.051	0.053	0.058	0.063
Total Products + Ref. LPG	**8.422**	**8.270**	**7.893**	**7.658**	**7.514**	**7.424**	**7.464**	**7.677**	**8.379**	**9.150**
Saskatchewan										
Aviation Gasoline	0.032	0.030	0.031	0.030	0.030	0.029	0.028	0.026	0.025	0.025
Motor Gasoline	5.219	5.243	5.266	5.148	5.029	4.921	4.701	4.410	4.366	4.732
Av. Turbo – Kerosene (Jet A)	0.003	0.002	0.003	0.003	0.003	0.003	0.003	0.004	0.006	0.006
– Naphtha (Jet B)	0.248	0.219	0.224	0.227	0.230	0.238	0.254	0.317	0.374	0.404
– Total	0.251	0.222	0.227	0.229	0.233	0.241	0.257	0.321	0.379	0.410
Light Fuel & Kerosene	0.893	0.639	0.607	0.539	0.506	0.475	0.384	0.295	0.297	0.263
Diesel Fuel Oil	2.825	3.072	3.410	3.493	3.520	3.552	3.656	3.989	4.581	5.134
Heavy Fuel Oil	0.341	0.242	0.201	0.207	0.207	0.208	0.207	0.234	0.249	0.258
Asphalt	0.471	0.394	0.398	0.402	0.406	0.410	0.422	0.441	0.461	0.480
Lubes and Greases	0.136	0.140	0.144	0.149	0.153	0.158	0.171	0.193	0.215	0.237
Petrochemical Feedstock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Products	0.524	0.525	0.537	0.540	0.543	0.546	0.557	0.586	0.629	0.681
Total Oil Products	10.692	10.507	10.822	10.737	10.627	10.539	10.383	10.496	11.201	12.219
Refinery LPG	0.244	0.226	0.234	0.233	0.231	0.230	0.229	0.235	0.252	0.275
Total Products + Ref. LPG	**10.936**	**10.733**	**11.056**	**10.970**	**10.858**	**10.769**	**10.612**	**10.731**	**11.453**	**12.494**

Table A7-33 (Cont'd)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Alberta										
Aviation Gasoline	0.081	0.068	0.076	0.076	0.075	0.074	0.072	0.069	0.065	0.065
Motor Gasoline	13.139	12.738	12.453	11.916	11.515	11.167	10.471	9.738	9.930	11.028
Av. Turbo – Kerosene (Jet A)	1.306	1.316	1.294	1.302	1.317	1.363	1.453	1.841	2.244	2.423
– Naphtha (Jet B)	0.763	0.629	0.670	0.666	0.666	0.681	0.700	0.828	0.935	1.009
– Total	2.069	1.945	1.964	1.968	1.983	2.044	2.153	2.669	3.178	3.432
Light Fuel & Kerosene	0.444	0.349	0.329	0.258	0.255	0.255	0.253	0.175	0.149	0.126
Diesel Fuel Oil	7.189	7.445	7.400	7.180	7.270	7.265	7.364	8.030	8.984	9.189
Heavy Fuel Oil	0.180	0.167	0.142	0.129	0.127	0.126	0.108	0.115	0.127	0.138
Asphalt	1.530	1.526	1.567	1.609	1.651	1.692	1.817	2.025	2.233	2.441
Lubes and Greases	0.356	0.371	0.386	0.401	0.416	0.431	0.476	0.551	0.626	0.701
Petrochemical Feedstock	0.008	0.009	0.336	0.772	0.827	0.857	0.857	0.857	0.857	0.857
Other Products	2.170	2.163	2.177	2.171	2.176	2.180	2.208	2.323	2.508	2.689
Total Oil Products	27.165	26.780	26.831	26.479	26.295	26.091	25.778	26.552	28.656	30.667
Refinery LPG	1.128	1.099	1.102	1.087	1.081	1.074	1.064	1.101	1.190	1.273
Total Products + Ref. LPG	**28.293**	**27.880**	**27.932**	**27.566**	**27.376**	**27.165**	**26.842**	**27.652**	**29.846**	**31.940**
British Columbia and Territories										
Aviation Gasoline	0.118	0.115	0.114	0.114	0.114	0.114	0.113	0.112	0.110	0.110
Motor Gasoline	11.310	10.669	10.669	10.578	10.405	10.275	10.248	10.219	10.223	10.968
Av. Turbo – Kerosene (Jet A)	0.843	0.866	0.812	0.806	0.804	0.820	0.838	0.989	1.122	1.212
– Naphtha (Jet B)	0.911	0.720	0.800	0.796	0.796	0.815	0.837	0.992	1.122	1.211
– Total	1.753	1.585	1.613	1.602	1.600	1.635	1.676	1.982	2.244	2.423
Light Fuel & Kerosene	2.436	1.982	2.103	1.980	1.826	1.730	1.397	0.898	0.816	0.820
Diesel Fuel Oil	6.715	6.613	6.668	6.865	6.989	7.163	7.501	8.403	9.298	9.887
Heavy Fuel Oil	3.755	2.370	2.173	2.181	1.898	1.872	2.005	2.245	2.650	2.981
Asphalt	0.578	0.657	0.675	0.692	0.710	0.728	0.782	0.872	0.961	1.051
Lubes and Greases	0.286	0.300	0.315	0.329	0.344	0.359	0.402	0.475	0.548	0.621
Petrochemical Feedstock	0.165	0.146	0.148	0.150	0.151	0.153	0.156	0.156	0.156	0.156
Other Products	1.073	0.996	1.007	1.016	1.007	1.012	1.034	1.091	1.167	1.254
Total Oil Products	28.188	25.433	25.484	25.506	25.043	25.040	25.314	26.452	28.174	30.271
Refinery LPG	0.633	0.423	0.424	0.424	0.416	0.417	0.422	0.443	0.473	0.509
Total Products + Ref. LPG	**28.821**	**25.856**	**25.908**	**25.931**	**25.460**	**25.456**	**25.736**	**26.895**	**28.647**	**30.780**

Table A7-34
Refinery Feedstock Requirements – Canada and Regions
NEB Projection

(Thousands of Cubic Metres)

	Actual				Forecast					
	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Canada										
Total Refined Petroleum Product Domestic Demand	82373	76417	75198	74044	71353	70398	69123	68076	71566	74473
Add Refinery LPG	2293	2378	1978	1970	1983	2021	2050	2139	2259	2385
Deduct Product Imports	–2654	–3139	–2806	–2797	–2334	–2982	–3404	–990	–1040	–1621
Add Product Exports	4863	6987	5786	1457	1507	1562	1559	1783	1181	1165
Add Inventory Build/(Draw)	–3241	–2065	–3151	–425	20	61	–343	419	125	–278
Add Product Losses and Own Use	6591	5607	5402	5290	5094	5002	4921	4876	5126	5324
Deduct Refinery Gains	–1807	–1710	–1798	–1732	–1691	–1665	–1609	–1666	–1723	–1767
Refinery Feedstock Requirements	88418	84478	80603	77807	75932	74407	72296	74637	77494	79682
Per Day	242.7	231.7	220.2	213.2	208.0	203.9	198.1	204.5	211.7	218.3
Deduct Gas Plant Butanes Supplied to Refineries	873	978	–1244	–1205	–1168	–1132	–1132	–1168	–1205	–1241
Refinery Requirements for Crude Oil & Equivalent	87545	83500	79359	76602	74764	73275	71164	73469	76289	78441
Per day	239.8	228.8	216.8	209.9	204.8	200.8	195.0	201.3	209.0	214.9
Atlantic										
Total Refined Petroleum Products Domestic Demand	10318	8908	9540	9760	9011	9468	9444	7068	7179	7571
Add Refinery LPG	212	243	207	205	205	219	247	263	283	316
Deduct Product Imports	–1464	–1182	–1688	–1707	–1394	–2017	–2414	–200		–431
Add Product Exports	345	705	650						100	175
Deduct Net Inter-regional Transfers In	–801	–615	–327	–582	–413	–419	–434	–428	–439	–462
Add Inventory Build/(Draw)	–754	–17	–263	–38	23	29	–258	58	54	139
Add Product Losses and Own Use	652	485	483	500	466	496	521	382	391	445
Deduct Refinery Gains	–238	–175	–162	–153	–149	–146	–132	–135	–144	–146
Refinery Feedstock Requirements	8405	8275	8440	7985	7749	7630	6974	7008	7424	7607
Per Day	22.8	22.3	23.1	21.9	21.2	20.9	19.1	19.2	20.3	20.8
Deduct Gas Plant Butanes Supplied to Refiners	—	—	—	—	—	—	—	—	—	—
Refinery Requirements for Crude Oil & Equivalent	8405	8275	8440	7985	7749	7630	6974	7008	7424	7607
Per Day	23.0	22.7	23.1	21.9	21.2	20.9	19.1	19.2	20.3	20.8

Table A7-34 (Cont'd)

	Actual				Forecast					
	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Quebec										
Total Refined Petroleum Product Domestic Demand	20810	18637	16966	16000	15484	15069	14437	14527	15168	15561
Add Refinery LPG	514	457	445	446	444	445	454	482	511	540
Deduct Product Imports	–521	–1225	–600	–600	–550	–575	–600	–400	–650	–800
Add Product Exports	1299	942	1364	100	150	100				
Deduct Net Inter-regional Transfers In	2061	1187	1874	1304	1084	1043	1069	1105	1158	1219
Add Inventory Build/(Draw)	–834	–942	–1146	–200	–9	–34	25	113	37	–316
Add Product Losses and Own Use	1618	1307	1347	1255	1215	1182	1133	1140	1192	1229
Deduct Refinery Gains	–442	–472	–473	–426	–415	–401	–385	–396	–406	–405
Refinery Feedstock Requirements	24282	20108	19777	17879	17403	16829	16133	16571	17010	17028
Per Day	66.5	55.1	54.0	49.0	47.7	46.1	44.2	45.4	46.5	46.7
Deduct Gas Plant Butanes Supplied to Refineries	—	—	—	—	—	—	—	—	—	—
Refinery Requirements for Crude Oil & Equivalent	24282	20108	19777	17879	17403	16829	16133	16571	17010	17028
Per Day	66.5	55.1	54.0	49.0	47.7	46.1	44.2	45.4	46.5	46.7
Ontario										
Total Refined Petroleum Product Domestic Demand	25270	24537	23933	23748	22638	21775	21212	21675	22595	22661
Add Refinery LPG	796	820	664	663	684	711	703	725	744	755
Deduct Product Imports	–349	–527	–378	–400	–300	–300	–300	–300	–300	–300
Add Product Exports	2864	3943	2687	1200	1253	1372	1469	1693	991	900
Deduct Net Inter-regional Transfers In	–1449	–1022	–2044	–754	–705	–659	–670	–713	–760	–788
Add Inventory Build/(Draw)	–1416	–679	–726	–122	–14	44	–74	205	–88	–259
Add Product Losses and Own Use	2946	2486	2425	2401	2292	2209	2153	2200	2298	2311
Deduct Refinery Gains	–554	–520	–603	–608	–589	–574	–559	–582	–580	–574
Refinery Feedstock Requirements	28218	28792	25958	26128	25259	24578	23935	24903	24900	24706
Per Day	77.6	78.7	70.9	71.6	69.2	67.3	65.6	68.2	68.0	67.7
Deduct Gas Plant Butanes Supplied to Refineries	–108	–135	–154	–150	–145	–140	–145	–145	–150	–154
Refinery Requirements for Crude Oil & Equivalent	28110	28657	25804	25978	25114	24438	23790	24763	24750	24452
Per Day	77.0	78.5	70.5	71.2	68.8	67.0	65.2	67.8	67.8	67.3

Table A7-34 (Cont'd)

	Actual					Forecast				
	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Prairies & Northwest Territories										
Total Refined Petroleum Product Domestic Demand	16537	15886	15807	15574	15420	15287	15137	15513	16728	18048
Add Refinery LPG	542	602	507	501	498	494	491	507	548	588
Deduct Product Imports	–5	–3								
Add Product Exports	145	807	523	157	104	90	90	0	90	90
Deduct Net Inter-regional Transfers In	1108	1332	1353	1066	1068	1163	945	1052	1204	1176
Add Inventory Build/(Draw)	–251	–110	–819	–15	–35	15	–38	3	67	110
Add Product Losses and Own Use	906	924	797	786	780	774	768	792	857	922
Deduct Refinery Gains	–401	–330	–347	–346	–341	–341	–333	–343	–373	–400
Refinery Feedstock Requirements	18474	19108	17821	17723	17494	17482	17061	17614	19121	20534
Per Day	51.2	53.1	48.7	48.6	47.9	47.9	46.8	48.3	52.2	56.3
Deduct Gas Plant Butanes Supplied to Refineries	717	795	–1030	–1000	–963	–992	–987	–1028	–1055	–1087
Refinery Requirements for Crude Oil & Equivalent	17757	18313	16731	16668	16471	16490	16074	16586	18066	19447
Per Day	48.6	50.2	45.7	45.7	45.1	45.1	44.0	45.4	49.4	53.3
British Columbia & Yukon										
Total Refined Petroleum Product Domestic Demand	9438	8449	8952	8962	8800	8799	8893	9293	9896	10632
Add Refinery LPG	229	256	155	155	152	152	155	162	173	186
Deduct Product Imports	–315	–202	–140	–90	–90	–90	–90	–90	–90	–90
Add Product Exports	210	590	562							
Deduct Net Inter-regional Transfers In	–919	–879	–862	–1034	–1034	–1128	–911	–1016	–1163	–1145
Add Inventory Build/(Draw)	14	–317	–197	–50	55	7	2	40	55	48
Add Product Losses and Own Use	469	405	350	348	341	341	346	362	388	417
Deduct Refinery Gains	–172	–213	–212	–199	–197	–194	–201	–210	–222	–241
Refinery Feedstock Requirements	9113	8345	8608	8092	8027	7888	8194	8541	9037	9807
Per Day	25.0	22.6	23.5	22.2	22.0	21.6	22.4	23.4	24.7	26.9
Deduct Gas Plant Butanes Supplied to Refineries	43	48	60	55	60	60	60	60	60	60
Refinery Requirements for Crude Oil & Equivalent										
Per Day	25.0	22.9	23.5	22.2	22.0	21.6	22.4	23.4	24.7	26.9

Table A7-35
Crude Oil and Equivalent Supply and Demand – Canada
NEB Projections

(Thousands of Cubic Metres Per Day)

Total Crude Oil	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Domestic Supply										
Actual Production & Productive Capacity										
Heavy	35.4	41.6[1]	49.7	50.7	51.1	52.1	39.1	46.1	51.7	59.2
Light and Medium Crude Oil and Equivalent	181.9	188.6[2]	199.7	190.2	177.5	168.5	161.9	182.4	171.2	157.4
Gas Plant Butanes And Other	4.6	5.9	5.3	5.3	5.3	5.3	5.4	5.5	5.4	5.5
Total Domestic Supply of Crude Oil and Equivalent	228.9	236.1	254.7	246.2	233.9	225.9	206.5	233.9	228.4	221.9
Domestic Feedstock Requirements										
a) From Indigenous Sources:										
Heavy	14.7	11.3	15.1	15.8	16.2	16.7	17.8	19.4	20.8	22.6
Light and Medium Crude Oil and Equivalent	177.6	177.9	169.7	163.3	158.3	153.9	148.7	179.7	171.2	157.4
Gas Plant Butanes and Other	4.6	5.9	5.3	5.3	5.3	5.3	5.4	5.5	5.4	5.5
b) From Foreign Sources	45.0	34.9	30.0	28.8	28.2	27.9	26.1	—	14.3	32.0
c) Refinery Inventory (Build)/Draft	0.8	1.7	—	—	—	—	—	—	—	—
Total Feedstock Requirements	242.7	231.7	220.2	213.2	208.0	203.9	198.1	204.5	211.7	218.3
Excess of Domestic Supply Over Domestic Requirements										
Heavy	20.7	30.3	34.6	34.9	34.9	35.4	21.3	26.7	30.9	36.6
Light and Medium	4.3	10.7	30.0	26.9	19.2	14.6	13.2	2.7	—	—
Total	25.0	41.0	64.6	61.8	54.1	50.0	34.5	29.4	30.9	36.6

(1) Productive Capacity was 43.9 thousand cubic metres per day
(2) Productive Capacity was 197.6 thousand cubic metres per day

Table A7-35 (Cont'd)

Total Crude Oil	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
1. Heavy Crude Oil										
Domestic Supply										
Actual Production and Productive Capacity	35.4	41.6[1]	49.7	50.7	51.1	52.1	39.1	46.1	51.7	59.2
Domestic Feedstock Requirements from Indigenous Sources										
Atlantic	—	—	—	—	—	—	—	—	—	—
Quebec	3.9	1.5	3.4	3.5	3.6	3.7	4.0	4.3	4.6	5.0
Ontario	7.0	5.7	6.5	6.9	7.0	7.2	7.4	7.8	8.3	8.9
Eastern Canada	10.9	7.2	9.9	10.4	10.6	10.9	11.4	12.1	12.9	13.9
Prairies	3.9	4.5	5.1	5.3	5.5	5.7	6.3	7.2	7.8	8.6
British Columbia	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Western Canada	4.0	4.6	5.2	5.4	5.6	5.8	6.4	7.3	7.9	8.7
Canada	14.7	11.3	15.1	15.8	16.2	16.7	17.8	19.4	20.8	22.6
Excess Supply Over Domestic Requirements	20.7	30.3	34.6	34.9	34.9	35.4	21.3	26.7	30.9	36.6
2. Light and Medium Crude Oil and Equivalent										
Domestic Supply										
Actual Production and Productive Capacity										
East Coast	—	—	—	—	—	—	—	34.0	34.0	34.0
Beaufort Sea	—	—	—	—	—	—	—	10.0	10.0	10.0
W. Canada	181.9	188.6	199.7	190.2	177.5	168.5	161.9	131.4	128.2	114.4
Canada	181.1	188.6	199.7	190.2	177.5	168.5	161.9	182.4	171.2	157.4

Table A7-35 (Cont'd)

Total Crude Oil	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Domestic Feedstock Requirements from Indigenous Supply Sources										
Atlantic	3.7	7.8	9.0	9.0	9.0	9.0	9.0	19.2	20.3	20.8
Quebec	35.4	32.4	34.1	29.0	27.6	25.9	23.7	40.6	27.1	13.2
Ontario	68.2	70.6	62.1	62.4	59.9	57.8	55.8	58.0	57.4	51.8
Eastern Canada	107.3	110.8	105.2	100.4	96.5	92.7	88.5	117.8	104.8	85.5
Prairies	45.7	45.9	41.6	41.3	40.4	40.2	38.4	39.1	42.3	45.6
British Columbia	24.7	21.7	22.9	21.6	21.4	21.0	21.8	22.8	24.1	26.3
Western Canada	70.4	67.6	64.5	62.9	61.8	61.2	60.2	61.9	66.4	71.9
Canada	177.6	177.9	169.7	163.3	158.3	153.9	148.7	179.7	171.2	157.4
Excess Supply Over Domestic Requirements	4.3	10.7	30.0	26.9	19.2	14.6	13.2	2.7	—	—

Table A8-1
Historical Data – Production of Natural Gas Liquids

(Thousands of Cubic Metres Per Day)

		1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971
Ethane	–Gas Plants[1]	—	—	—	—	—	—	—	—	.1	.3	.4	1.0
Propane	–Gas Plants[1]	1.0	1.3	1.6	1.8	3.0	4.6	5.6	6.4	7.1	8.2	9.8	12.2
	–Refineries[2]	.7	.9	.9	1.9	1.7	1.7	1.9	2.0	2.0	2.1	2.3	2.3
	–Total	1.7	2.2	2.5	3.7	4.7	6.3	7.5	8.4	9.1	10.3	12.1	14.5
Butanes	–Gas Plants[1]	.8	1.0	1.2	1.4	2.5	3.1	3.7	4.2	4.8	5.2	6.4	8.0
	–Refineries[2]	.6	.8	.8	1.6	1.4	1.6	1.8	1.7	1.6	1.5	1.2	.7
	–Total	1.4	1.8	2.0	3.0	3.9	4.7	5.5	5.9	6.4	6.7	7.6	8.7
Pentanes Plus	–Gas Plants[1]	1.3	2.4	4.6	8.1	10.6	11.9	12.4	13.0	14.1	16.6	19.0	20.6

		1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
Ethane	–Gas Plants[1]	.9	1.1	1.7	1.7	1.5	1.8	4.8	10.8	13.1	13.8	12.7
Propane	–Gas Plants[1]	14.5	16.4	16.3	17.0	16.2	16.3	15.5	16.9	16.2	15.8	15.8
	–Refineries[2]	2.3	2.6	2.6	3.1	3.5	3.7	3.6	3.5	3.8	3.7	3.2
	–Total	16.8	19.0	18.9	20.1	19.7	20.0	19.1	20.4	20.0	19.5	19.0
Butanes	–Gas Plants[1]	9.6	10.8	11.0	11.2	10.8	10.9	10.1	10.9	10.2	9.8	9.8
	–Refineries[2]	.4	.7	.9	1.0	1.0	1.4	1.5	1.9	2.3	2.9	2.5
	–Total	10.0	11.5	11.9	12.2	11.8	12.3	11.6	12.8	12.5	12.7	12.3
Pentanes Plus	–Gas Plants[1]	26.4	27.1	26.0	24.4	21.4	21.1	19.0	18.8	17.0	16.4	16.1

(1) Provincial NGL gas plant production figures have been adjusted upwards to account for an estimate of each gas liquid component in mixes injected in miscible flood or other injection schemes. Production of specification ethane did not begin until 1974.

(2) Refinery production is net of own use. Source: 1960-1974 Statistics Canada. 1975-1982 NEB 145 summaries: 1960-1964 LPG total available only. Above statistics assume 54 percent propane and 46 percent butanes during 1960-64.

Table A8-2
Natural Gas Liquids Production
NEB Projection

(Thousands of Cubic Metres Per Day)

	Ethane	Propane				Butanes				Pentanes Plus		
Year	Total	Gas Plants	Refineries	Frontier	Total	Gas Plants	Refineries	Frontier	Total	Gas Plants	Frontier	Total
1983	13.5	15.2	3.5	.0	18.7	9.5	2.6	.0	12.1	15.1	.0	15.1
1984	17.4	15.4	3.4	.0	18.8	9.6	2.5	.0	12.1	14.9	.0	14.9
1985	21.7	16.7	3.3	.0	20.0	10.4	2.4	.0	12.8	15.9	.0	15.9
1986	26.5	17.9	3.2	.0	21.1	11.0	2.3	.0	13.3	16.4	.0	16.4
1987	28.6	20.1	3.2	.0	23.3	12.2	2.3	.0	14.5	18.0	.0	18.0
1988	28.3	20.5	3.2	.0	23.7	12.4	2.3	.0	14.7	18.1	.0	18.1
1989	28.1	21.3	3.1	.0	24.4	12.9	2.3	.0	15.2	18.2	.0	18.2
1990	27.9	21.1	3.1	1.3	25.5	12.6	2.2	.8	15.6	17.5	1.9	19.4
1991	27.5	20.5	3.1	1.3	24.9	12.2	2.2	.8	15.2	16.7	1.9	18.6
1992	27.1	19.9	3.1	1.3	24.3	11.8	2.2	.8	14.8	16.2	1.9	18.1
1993	26.3	19.2	3.2	1.3	23.7	11.4	2.3	.8	14.5	15.6	1.9	17.5
1994	25.5	18.5	3.2	1.3	23.0	11.0	2.3	.8	14.1	15.0	1.9	16.9
1995	24.6	17.8	3.2	1.3	22.3	10.5	2.3	.8	13.6	14.5	1.9	16.4
1996	24.0	17.2	3.2	1.3	21.7	10.1	2.3	.8	13.2	14.0	1.9	15.9
1997	23.2	16.5	3.2	1.3	21.0	9.7	2.3	.8	12.8	13.3	1.9	15.2
1998	22.3	15.7	3.2	1.3	20.2	9.2	2.3	.8	12.3	12.8	1.9	14.7
1999	20.7	15.0	3.3	1.3	19.6	8.8	2.3	.8	11.9	12.0	1.9	13.9
2000	19.1	14.3	3.3	1.3	18.9	8.3	2.4	.8	11.5	11.4	1.9	13.3
2001	18.6	13.9	3.3	1.3	18.5	8.0	2.4	.8	11.2	11.1	1.9	13.0
2002	17.5	13.4	3.3	1.3	18.0	7.8	2.4	.8	11.0	10.6	1.9	12.5
2003	17.5	13.5	3.3	1.3	18.1	7.8	2.4	.8	11.0	10.7	1.9	12.6
2004	17.6	13.7	3.4	1.3	18.4	7.9	2.4	.8	11.1	10.8	1.9	12.7
2005	17.6	13.9	3.4	1.3	18.6	8.0	2.4	.8	11.2	10.8	1.9	12.7

Table A8-3
Ethane Supply From Gas Plants
Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
Amoco	13.7	15.6	18.1	20.3	21.4	25.3	25.8	25.2	22.1
Dome – Low(1)	13.6	17.7	19.4	22.7	25.0	30.8	33.1	34.3	35.2
Dome – High(1)	13.6	17.7	18.6	21.7	24.5	31.6	32.0	35.0	36.6
EUPC	13.8	16.0	16.2	22.2	—	24.4	22.9	—	—
Gulf(1)	—	17.5	19.1	25.4	27.0	27.0	28.6	27.0	—
Imperial(2)	15.8	18.0	19.0	24.1	28.7	30.7	26.9	21.7	—
Husky/NOVA(3)	12.1	13.7	15.0	15.5	15.6	17.4	18.6	20.5	19.7
Petro-Canada(2)	14.4	14.4	14.8	15.3	16.3	16.3	14.9	14.2	14.1
Shell	–	19.1	22.5	23.9	23.6	22.6	22.9	23.1	—
NEB	13.5	17.4	21.7	26.5	28.6	27.9	24.6	19.1	17.6

(1) Includes production from reproduced miscible fluids and frontiers.
(2) Includes frontiers.
(3) Supply from Alberta reprocessing plants only.

Table A8-4
Propane Supply from Gas Plants(5)
Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
B.C.(1)	.2	.2	.2	.2	.2	.2	.2	.2	.1
Amoco(3)	15.7	15.9	16.3	16.5	17.0	19.5	20.5	19.4	16.3
Dome – Low(2)	15.1	17.0	17.5	18.3	18.4	18.1	19.3	17.9	15.0
Dome – High(2)	15.1	17.0	17.5	18.2	18.2	17.5	18.5	18.5	15.2
Gulf(2)	—	17.0	17.0	18.6	18.6	20.2	21.7	20.2	—
Imperial(3)	15.5	15.8	15.8	16.9	18.3	18.3	16.1	14.2	—
Petro-Canada(3)	15.1	15.1	15.6	16.1	17.1	18.3	17.0	16.6	15.9
Shell(4)	–	13.3	13.1	13.2	13.2	12.9	12.1	13.5	—
NEB(3)	15.2	15.4	16.7	17.9	20.1	22.4	19.1	15.6	15.2

(1) British Columbia only.
(2) Includes production from reproduced miscible fluids and frontier.
(3) Includes frontier production.
(4) Alberta only.
(5) Includes reprocessing plants.

Table A8-5
Butanes Supply from Gas Plants[4]
Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
B.C.[5]	.3	.3	.3	.3	.3	.3	.3	.3	.2
Amoco	9.8	9.9	10.0	9.9	10.2	11.5	12.2	11.3	9.4
Dome – Low[1]	9.6	10.6	10.9	11.1	10.9	10.4	10.3	9.3	7.6
Dome – High[1]	9.6	10.6	10.9	11.0	10.8	10.0	9.9	9.8	8.1
Gulf[1]	—	7.4	7.4	7.4	7.4	9.0	9.0	7.4	—
Imperial[2]	9.7	10.0	9.9	10.3	11.0	10.9	9.4	7.7	—
Petro-Canada[2]	9.0	9.0	9.2	9.4	9.9	10.4	9.6	9.3	8.7
Shell[3]	—	8.0	7.9	7.9	7.9	7.5	7.1	8.1	—
NEB[2]	9.5	9.6	10.4	11.0	12.2	13.4	11.3	9.1	8.8

(1) Includes production from reproduced miscible fluids and frontiers.
(2) Includes frontiers.
(3) Alberta only.
(4) Includes reprocessing plants.
(5) British Columbia only.

Table A8-6
Pentanes Plus Supply from Gas Plants[5]
Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
AERCB[1]	14.9	14.4	14.5	14.6	14.6	15.0	14.5	11.2	7.4
B.C.[2]	.5	.5	.5	.5	.5	.5	.5	.5	.4
Amoco[3]	14.0	13.4	13.6	14.4	14.8	15.0	15.4	18.0	19.5
CPA	—	13.0	14.0	14.0	14.0	14.0	10.0	—	—
Dome – Low[4]	16.0	16.9	17.5	18.0	18.2	16.6	17.3	14.6	12.3
Dome – High[4]	16.0	16.9	17.5	18.0	18.0	16.0	16.5	16.2	13.5
EUPC	15.0	16.0	16.0	16.0	15.0	14.0	14.0	14.0	12.0
Gulf	14.3	14.3	12.7	12.7	11.1	9.5	7.9	6.4	—
Imperial[4]	15.2	15.2	15.2	15.5	16.6	16.9	16.8	16.1	—
Petro-Canada[4]	15.0	15.8	16.2	16.5	16.6	18.2	14.5	12.8	9.1
Shell	—	15.0	14.3	13.6	13.2	12.0	11.2	12.6	—
Texaco	14.9	14.9	15.9	15.9	14.8	10.3	9.5	—	—
NEB[4]	15.1	14.9	15.9	16.4	18.0	19.4	16.4	13.3	12.7

(1) Alberta only.
(2) British Columbia only.
(3) Forecast of Alberta supply. Assumes frontier reserves will supplement Alberta deliverability after 2000.
(4) Includes frontiers.
(5) Includes reprocessing plants.

Table A8-7
Propane Supply from Refineries
Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
Amoco	3.2	3.4	3.7	3.7	3.8	4.1	4.5	4.9	5.5
Dome – Low	3.9	4.0	4.2	4.2	4.3	4.4	3.8	3.8	3.0
Dome – High	3.9	4.0	4.1	4.1	4.0	3.9	3.3	2.7	2.4
Imperial	4.3	4.3	4.3	4.0	3.8	3.5	3.5	3.5	—
Petro-Canada	3.4	3.4	3.5	3.6	3.6	3.7	3.7	4.1	4.3
NEB	3.5	3.4	3.3	3.2	3.2	3.1	3.2	3.3	3.4

Table A8-8
Butanes Supply from Refineries
Comparison of Submittors' Views

(Thousands of Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
Amoco	2.5	2.8	3.5	3.5	3.6	3.8	4.2	4.6	5.1
Dome – Low	4.2	4.1	4.3	4.4	4.6	4.7	4.0	3.4	3.0
Dome – High	4.2	4.1	4.1	4.2	4.3	4.1	3.4	2.7	2.4
Imperial	2.7	2.7	2.7	2.6	2.6	2.7	2.7	2.7	—
Petro-Canada	2.5	2.5	2.4	2.4	2.4	2.3	2.3	2.2	2.3
NEB	2.6	2.5	2.4	2.3	2.3	2.2	2.3	2.4	2.4

Table A8-9
Ethane Production by Gas Plant
NEB Projection

(Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
Alberta									
Cochrane	3918	5000	5500	6000	6000	6000	4600	1600	600
Edmonton Ethane	1465	1470	1000	1700	1700	1800	1200	1200	1200
Elmworth	0	0	1000	1385	1300	1100	800	545	375
Empress	6283	9000	10700	13600	16000	16000	16000	13800	13900
Judy Creek	0	0	1600	2030	1990	1720	1000	800	675
Jumping Pound	198	400	375	350	330	265	200	160	80
Rainbow	682	660	640	630	560	400	220	180	200
Waterton	656	650	605	565	530	430	300	210	100
Others	200	190	180	170	160	140	205	570	390
Alberta Total	13402	17370	21600	26430	28570	27855	24525	19065	17520
Saskatchewan Total	55	55	52	50	48	44	38	34	31
Canada Total	13457	17425	21652	26480	28618	27899	24563	19099	17551

Table A8-10
Propane Production by Gas Plant
NEB Projection

(Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
British Columbia Total	171	167	200	600	725	725	725	725	725
Alberta									
From Existing Plants									
Acheson (ICG)	79	69	59	51	44	28	14	0	0
Ante Creek (Amoco)	27	26	24	23	21	17	12	8	6
Bigoray (Chevron)	25	26	24	21	19	13	7	4	2
Bonnie Glen (Texaco)	1278	994	800	670	553	411	277	655	420
Brazeau (Petro-Canada)	74	80	86	78	65	37	15	6	1
Caroline (All Plants)	110	110	110	110	108	105	77	46	27
Carson Creek (Mobil)	295	278	256	231	222	188	76	18	11
Carstairs (Dome)	235	209	196	190	168	118	69	38	24
Cranberry (Dome)	102	102	103	104	101	95	82	50	30
Crossfield (Petrogas)	113	106	95	85	76	54	31	14	7
Elmworth (Cdn Hunter)	0	0	300	400	374	308	225	153	106
Ferrier (Almerada)	167	161	156	142	129	98	62	39	22
Ferrier (Texas-Pacific)	23	22	20	18	17	13	8	5	3
Garrington (All Plants)	70	61	45	33	25	12	0	0	0
Ghost Pine (Gulf)	20	21	21	21	21	18	12	8	5
Gilby (All Plants)	101	98	95	91	86	70	53	34	22
Golden Spike (Esso)	117	120	122	123	124	119	100	13	3
Harmattan-Elkton (Cdn. Sup.)	375	412	440	439	437	422	311	135	59
Homeglen Rimbey (Gulf)	995	918	794	686	600	432	232	142	55
Hussar (Canterra)	47	52	52	52	52	52	52	52	40
Judy Creek (Esso)	1500	1475	1420	1367	1220	1100	600	510	475
Jumping Pound (Shell)	144	143	142	138	132	110	83	66	52
Kaybob (Petro-Canada)	170	180	170	153	139	109	72	48	33
Kaybob South (Chevron)	400	359	379	386	371	306	178	89	45
Kaybob South (Dome)	300	248	200	170	137	74	24	14	0
Leaman (Dome)	16	16	15	13	12	9	5	3	2
Leduc-Woodbend (Esso)	74	64	63	57	89	115	85	17	0
Mitsue (Chevron)	237	201	147	125	104	79	53	37	27
Morinville (Norcen)	28	25	22	19	16	10	5	2	0
Nevis (Chevron)	17	12	9	7	5	0	0	0	0
Nevis (Gulf)	319	295	265	237	189	112	70	48	31
Nipisi (Amoco)	136	125	114	105	95	72	45	28	17
Niton (Esso)	23	25	27	30	30	30	23	16	10
Olds (Amerada)	36	33	31	29	27	22	16	11	8
Paddle R (Cities Service)	152	142	132	115	100	66	31	14	0
Peco (Ocelot)	43	44	45	45	44	42	39	32	25
Pembina (Amoco)	100	90	85	80	75	65	50	40	28
Pembina (Chevron)	85	85	80	67	56	19	7	3	0
Pembina (Cities Service)	15	14	13	12	11	9	7	5	3
Pembina (Texaco)	25	24	24	23	22	20	17	14	12
Quirk Creek (Esso)	69	68	67	64	61	54	44	31	22
Rainbow (All Plants)	850	825	800	790	703	498	278	229	250

Table A8-10 (Cont'd)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
Redwater (Esso)	76	56	43	34	27	15	7	4	0
Ricinus (Amoco)	225	216	207	199	190	166	131	123	69
Simonette (Shell)	25	19	13	10	7	0	0	0	0
Strachan (Gulf)	64	59	54	50	45	32	19	6	0
Swan Hills (Shell)	56	52	49	46	43	36	27	21	16
Sylvan Lake (Chevron)	55	55	53	48	44	32	20	12	7
Sylvan Lake (Dome)	91	94	97	86	74	47	22	10	5
Turner Valley (W Decalta)	69	62	56	51	47	39	23	18	14
Twinning (Mobil)	29	28	28	28	27	24	17	10	6
Waterton (Shell)	295	285	280	275	267	207	129	89	66
Wayne Rosedale (All Plts)	50	48	45	37	34	23	14	9	7
Willesden Green (Dome)	56	53	50	47	44	37	27	20	14
Willesden Green (Texaco)	15	15	16	16	16	16	16	12	5
Other Field Plants	90	89	84	80	75	57	42	30	16
Cochrane	1066	1100	1100	1100	1100	1100	500	130	100
Edmonton Ethane	781	780	710	1100	1100	1175	775	775	750
Empress	2820	3200	3900	4200	5200	5700	5900	4500	4550
Sub-Total	14855	14569	14833	15007	15220	14237	11116	8446	7508
Field Plant Production from Uncommitted Reserves and Reserves Additions	0	491	1476	2131	4050	6033	5892	5030	5586
Alberta Total	14855	15060	16309	17138	19270	20270	17008	13476	13094
Saskatchewan Total	150	146	142	137	133	122	105	90	77
Canada Total	15176	15373	16651	17875	20128	21117	17838	14291	13896

Table A8-11
Butanes Production by Gas Plant
NEB Projection

(Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
British Columbia Total	20	215	250	400	440	440	440	440	440
Alberta									
From Existing Plants									
Acheson (ICG)	39	34	29	25	22	14	7	0	0
Ante Creek (Amoco)	21	20	19	17	16	13	9	7	5
Bigoray (Chevron)	10	10	10	9	8	5	3	1	1
Bonnie Glen (Texaco)	574	489	423	370	327	259	161	343	238
Brazeau (Petro-Canada)	42	45	48	44	36	20	8	3	1
Caroline (All Plants)	127	127	125	121	117	108	80	47	28
Carson Creek (Mobil)	187	180	165	156	144	120	49	15	6
Carstairs (Dome)	167	150	165	144	125	83	46	22	14
Cranberry (Dome)	55	58	61	65	65	65	60	37	22
Crossfield (Petrogas)	87	78	70	63	57	41	24	11	5
Elmworth (Cdn Hunter)	0	0	100	140	135	110	80	54	36
Ferrier (Almerada)	87	80	73	67	61	46	29	18	10
Ferrier (Texas-Pacific)	25	24	22	20	18	13	8	5	3
Garrington (All Plants)	44	33	25	18	14	6	0	0	0
Ghost Pipe (Gulf)	39	42	42	42	42	35	23	15	10
Gilby (All Plants)	78	74	71	67	62	48	32	21	12
Golden Spike (Esso)	66	65	64	63	62	57	47	7	1
Harmattan-Elkton (Cdn. Sup.)	277	294	317	315	313	298	211	92	40
Homeglen Rimbey (Gulf)	576	558	478	408	350	239	106	63	25
Hussar (Canterra)	42	46	46	46	46	46	46	46	36
Judy Creek (Esso)	1000	859	751	697	622	569	306	270	250
Jumping Pound (Shell)	116	116	117	113	108	90	67	54	44
Kaybob (Petro-Canada)	116	104	92	83	75	57	37	25	18
Kaybob South (Chevron)	422	368	390	396	381	314	183	91	45
Kaybob South (Dome)	390	330	260	216	175	78	15	9	0
Leaman (Dome)	4	4	3	3	3	2	1	1	1
Leduc-Woodbend (Esso)	89	85	84	76	119	153	113	23	0
Mitsue (Chevron)	229	195	142	121	101	77	51	36	26
Morinville (Norcen)	17	15	13	11	10	6	3	1	0
Nevis (Chevron)	15	11	8	6	5	0	0	0	0
Nevis (Gulf)	213	200	184	166	137	90	68	47	29
Nipisi (Amoco)	144	133	121	110	99	74	45	27	16
Niton (Esso)	31	33	36	40	40	40	31	21	14
Olds (Amerada)	27	25	23	22	20	17	12	8	6
Paddle R (Cities Service)	73	69	60	52	46	30	14	7	0
Peco (Ocelot)	15	16	16	16	16	15	14	12	10
Pembina (Amoco)	90	80	66	60	55	44	31	28	20
Pembina (Chevron)	40	40	37	31	27	9	3	2	0
Pembina (Cities Service)	15	14	13	12	11	9	7	5	3
Pembina (Texaco)	21	21	20	19	19	17	14	12	10
Quirk Creek (Esso)	48	47	47	45	43	38	31	22	15
Rainbow (All Plants)	700	692	621	551	490	351	201	165	180

Table A8-11 (Cont'd)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
Redwater (Esso)	59	45	36	29	24	15	8	5	0
Ricinus (Amoco)	146	140	134	129	124	108	86	80	44
Simonette (Shell)	16	11	8	6	4	0	0	0	0
Strachan (Gulf)	75	68	63	58	52	38	23	8	0
Swan Hills (Shell)	33	31	29	27	25	21	16	13	10
Sylvan Lake (Chevron)	36	36	35	32	29	22	14	8	5
Sylvan Lake (Dome)	54	59	64	57	49	30	14	6	3
Turner Valley (W Decalta)	53	45	39	34	30	22	9	7	6
Twinning (Mobil)	54	54	54	54	53	49	40	26	16
Waterton (Shell)	257	225	195	182	169	128	76	51	34
Wayne Rosedale (All Plts)	39	38	36	31	28	20	14	9	7
Willesden Green (Dome)	45	42	40	37	35	29	21	16	12
Willesden Green (Texaco)	10	10	10	10	10	10	10	7	4
Other Field Plants	89	84	79	74	69	58	42	31	23
Cochrane	379	396	396	396	396	396	178	47	36
Edmonton Ethane	330	330	298	464	464	494	325	325	315
Empress	1157	1350	1700	1850	2300	2550	2650	2000	2025
Sub-Total	**9190**	**8828**	**8673**	**8516**	**8483**	**7696**	**5802**	**4312**	**3720**
Field Plant Production from Uncommitted Reserves and Reserves Additions	0	463	1335	1953	3230	4373	4226	3517	3802
Alberta Total	**9190**	**9291**	**10008**	**10469**	**11713**	**12069**	**10028**	**7829**	**7522**
Saskatchewan Total	**98**	**95**	**92**	**89**	**87**	**79**	**68**	**58**	**50**
Canada Total	**9508**	**9601**	**10350**	**10958**	**12240**	**12588**	**10536**	**8327**	**8012**

Table A8-12
Pentanes Plus Production by Gas Plant
NEB Projection

(Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
From Existing Plants									
British Columbia									
Total	312	305	365	400	425	387	333	286	245
Alberta									
Bow River Pipelines									
Cessford (Dome)	10	10	10	10	10	10	10	10	10
Empress (Petro-Canada)	271	305	305	305	305	305	305	305	305
Provost	35	33	31	29	28	23	17	13	9
Wayne Rosedale (All Plants)	65	61	56	52	49	39	27	19	12
Others	56	54	51	46	42	32	19	11	7
Total	437	463	453	442	434	409	378	358	343
Co-Ed Pipe Line									
Caroline (Altana)	33	35	33	31	29	24	18	9	5
Caroline (Dome)	114	111	108	105	102	90	75	60	45
Cochrane	186	171	180	209	223	267	132	48	18
Edmonton Ethane	106	110	100	120	120	120	110	105	100
Empress (Dome)	220	235	265	302	455	535	560	385	445
Empress (Wolcott)	0	0	50	50	50	50	50	0	0
Ferrier (5 Plants)	98	90	82	74	68	54	37	25	17
Garrington (3 Plants)	23	17	13	10	7	1	0	0	0
Leduc-Woodbend	42	36	35	32	50	65	48	10	0
Minnehik-Buck Lake	72	95	95	95	95	95	51	24	0
Niton (Esso)	72	77	81	86	86	86	51	30	18
Quirk Creek	62	61	60	57	54	46	38	26	18
Ricinus	270	269	248	238	227	198	166	146	82
Ricinus West (Canterra)	106	102	95	88	81	65	48	35	19
Strachan (Gulf)	329	295	266	240	217	159	96	34	0
Others	24	22	21	20	19	16	13	11	8
Total	1757	1726	1732	1757	1883	1871	1493	948	775

Table A8-12 (Cont'd)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
Cremona Pipeline									
Burnt Timber	49	49	49	47	43	34	23	17	11
Carstairs	292	254	277	236	199	117	58	32	20
Crossfield (Petrogas)	157	136	121	107	96	67	37	0	0
Crossfield East	12	8	6	5	4	2	1	0	0
Harmattan (Canadian Superior)	467	501	539	538	537	518	392	170	74
Lone Pine Creek (Cdn Sup)	19	17	16	14	13	10	6	4	3
Lone Pine Creek (Dome)	82	83	85	82	80	74	40	13	9
Olds (Amerada)	68	63	59	55	52	42	30	0	0
Others	12	11	11	10	10	8	6	4	2
Total	1158	1122	1163	1094	1034	872	593	240	119
Federated Pipe Lines									
Total	3	3	3	3	3	3	3	3	3
Gibson Petroleum									
Acheson	24	21	18	16	13	9	4	0	0
Leaman	9	9	8	8	7	5	3	2	1
Okotoks	15	15	15	15	15	15	13	7	4
Paddle River	29	28	25	22	20	14	7	0	0
Wilson Creek	16	16	15	14	13	11	9	7	6
Worsley	2	2	2	2	2	2	2	2	1
Others	31	31	31	31	31	29	27	21	15
Total	126	122	114	108	101	85	65	39	27
Gulf Alberta Pipe Line									
Hussar (Canterra)	27	30	30	30	30	30	30	30	23
Nevis (Chevron)	24	18	13	10	7	0	0	0	0
Nevis (Gulf)	145	142	126	101	84	55	42	30	19
Others	62	60	55	50	46	41	37	32	27
Total	258	250	224	191	167	126	109	92	69
Imperial Pipe Line – Ellerslie									
Golden Spike	47	46	44	40	36	29	22	3	0
Morinville	17	15	13	11	10	6	3	0	0
Total	64	61	57	51	46	35	25	3	0
Imperial Pipe Line – Leduc									
Judy Creek	570	480	410	356	317	233	154	207	131
Total	570	480	410	356	317	233	154	207	131

Table A8-12 (Cont'd)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
	Imperial Pipe Line – Redwater								
Redwater	38	29	23	19	15	9	5	3	0
Total	38	29	23	19	15	9	5	3	0
	Murphy Oil								
Total	10	13	14	14	13	12	8	6	3
	Peace River Oil Pipe Line								
Carson Creek	197	184	175	164	155	122	53	21	7
Dunvegan	89	100	110	110	105	85	41	19	0
Gold Creek	90	94	87	81	75	65	52	52	50
Greencourt	14	16	15	15	15	12	6	3	0
Josephine	38	33	29	26	24	18	12	11	10
Kaybob	84	75	67	60	55	42	28	18	12
Kaybob South (Chevron)	1900	1605	1697	1727	1661	1368	796	331	140
Kaybob South (Dome)	1576	1433	1301	1263	905	342	0	0	0
Simonette (Shell)	44	40	37	34	31	24	22	0	0
Sturgeon Lake South	70	65	61	56	52	42	28	19	13
Whitecourt	27	27	27	26	25	21	17	13	10
Windfall	402	302	221	348	329	169	74	49	42
Others	30	28	26	25	24	20	16	12	9
Total	4561	4002	3853	3935	3456	2330	1145	548	293
	Pembina Pipe Line								
Brazeau (Canterra)	45	41	37	34	31	24	16	11	7
Brazeau (Dome)	140	146	152	158	158	128	67	38	22
Brazeau (Petro-Canada)	22	24	26	24	20	11	4	2	0
Peco	30	29	28	27	24	24	23	21	18
Willesden Green (Total)	44	39	35	30	27	18	13	6	3
Others	40	35	32	29	26	19	12	5	2
Total	321	314	310	302	286	224	135	83	52
	Rainbow Pipe Line								
Cranberry (Total)	292	295	296	296	296	296	266	164	101
Mitsue	83	72	64	58	52	40	27	19	14
Nipisi	89	82	74	68	62	47	29	18	11
Rainbow (Total)	351	331	299	268	240	179	109	141	286
Swan Hills (Shell)	15	14	13	12	11	10	0	0	0
Total	830	794	746	702	661	572	431	342	412

Table A8-12 (Cont'd)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
Rangeland Pipe Line									
Caroline (Dome)	85	84	81	79	76	71	46	27	16
Ferrier (Amerada)	64	59	54	49	45	34	21	13	0
Gilby (Texaco)	62	58	54	50	45	34	19	12	0
Gilby (Others)	97	93	90	87	80	65	48	26	16
Innisfail	31	26	23	20	17	11	5	2	0
Sylvan Lake (Chevron)	33	33	32	29	27	21	14	8	0
Sylvan Lake (Dome)	46	48	51	46	39	24	11	6	0
Sylvan Lake (Others)	52	49	45	40	36	27	19	13	7
Waterton	903	858	900	977	879	585	358	253	154
Wimborne	16	14	12	10	8	5	2	1	0
Others	90	17	16	15	13	10	8	6	4
Total	1479	1339	1358	1402	1265	887	551	367	197
Rimbey Pipe Line									
Homeglen-Rimbey	792	752	630	524	440	279	111	65	24
Total	792	752	630	524	440	279	111	65	24
Texaco Exploration									
Bonnie Glen	679	598	534	480	437	340	245	454	239
Total	679	598	534	480	437	340	245	454	239
Valley Pipe Line									
Jumping Pound	381	375	365	356	348	323	262	203	139
Turner Valley	45	38	32	27	23	14	4	3	2
Wildcat Hills	52	57	61	61	61	61	53	32	19
Total	478	470	458	444	432	398	319	238	160

Table A8-12 (Cont'd)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
				Truck and Tank Car					
Edson	153	153	148	139	131	111	78	49	10
Elmworth (Total)	130	127	236	278	262	220	156	103	69
Pembina (Amoco)	142	139	135	130	125	110	89	72	59
Pembina (Chevron)	520	434	299	216	154	80	60	40	20
Rosevear (Shell)	29	29	29	29	29	29	26	12	6
Rosevear (Suncor)	19	19	19	19	19	17	11	8	5
Sundance (Dome)	26	23	20	17	15	10	5	2	2
Twinning (Mobil)	23	22	22	21	20	18	12	7	5
Vulcan	27	24	22	20	18	14	8	5	3
Others	91	88	85	83	79	71	55	45	38
Total	**1160**	**1058**	**1015**	**952**	**852**	**680**	**500**	**343**	**217**
Sub-Total	**14721**	**13596**	**13097**	**12776**	**11842**	**9365**	**6270**	**4339**	**3064**
Field Plant Production from Uncommited Reserves and Reserves Additions	0	962	2349	3136	5677	7748	7858	6761	7454
Alberta Total	**14721**	**14558**	**15446**	**15912**	**17519**	**17113**	**14128**	**11100**	**10518**
				Saskatchewan					
Saskatchewan Total	**46**	**44**	**43**	**42**	**41**	**37**	**32**	**27**	**23**
				Canada					
Canada Total	**15079**	**14907**	**15854**	**16354**	**17985**	**17537**	**14493**	**11413**	**10786**

Table A8-13
Propane Production from Refineries
NEB Projection

(Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
Atlantic	247	257	245	239	236	224	221	230	250
Quebec	788	790	718	698	675	648	665	681	684
Ontario	1154	1067	1082	1041	1013	986	1026	1023	981
Prairies	942	892	891	880	878	857	886	959	1033
British Columbia	387	424	388	383	380	395	412	432	470
Canada Total	3518	3430	3324	3241	3182	3110	3210	3325	3418

Table A8-14
Butanes Production from Refineries
NEB Projection

(Cubic Metres Per Day)

	1983	1984	1985	1986	1987	1990	1995	2000	2005
Atlantic	210	187	178	174	172	163	160	167	182
Quebec	805	802	728	708	684	657	674	690	693
Ontario	808	748	758	729	710	691	719	717	687
Prairies	508	476	475	469	469	457	472	512	551
British Columbia	241	263	241	237	235	245	256	268	292
Canada Total	2572	2476	2380	2317	2270	2213	2281	2354	2405

Table A8-15
Natural Gas Liquids Net Export Licences

(Petajoules)

	Licence Number	Total Remaining	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	2005
Propane															
Dome	GL-31	43.4	3.4	3.4	3.4	3.7	4.9	5.0	4.3	4.3	4.2	4.1	2.7	—	—
Amoco	GL-32	26.0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.0	—	—
PanCanadian	GL-34	4.7	1.6	1.6	1.4	.1	—	—	—	—	—	—	—	—	—
Total Canada		74.1	7.4	7.4	7.2	6.2	7.3	7.4	6.7	6.7	6.6	6.5	4.7	—	—
Ethane															
Dome	GL-47	30.5	22.0	8.5	—	—	—	—	—	—	—	—	—	—	—
Dome	GL-51	249.3	26.5	37.2	50.8	42.9	35.2	24.2	14.2	11.2	5.2	1.9	—	—	—
Total Canada		279.8	48.5	45.7	50.8	42.9	35.2	24.2	14.2	11.2	5.2	1.9	—	—	—
Ethylene															
Dow Chemical of Canada Limited	EYL-1-76	48.0	8.0	8.0	8.0	8.0	8.0	8.0	—	—	—	—	—	—	—
Total Canada		48.0	8.0	8.0	8.0	8.0	8.0	8.0	—	—	—	—	—	—	—

Table A8-16
End Use Demand for Ethane, Propane and Butanes by Sector – Canada
NEB Projection

(Petajoules)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Ethane										
Residential										
Commercial										
Petrochemical	22.2	35.2	48.6	73.0	75.2	75.2	75.2	108.2	115.2	115.2
Other Industrial										
Transportation										
Total End Use	**22.2**	**35.2**	**48.6**	**73.0**	**75.2**	**75.2**	**75.2**	**108.2**	**115.2**	**115.2**
Propane										
Residential	34.5	36.2	33.6	31.0	30.8	30.8	30.9	33.6	33.5	35.8
Commercial	18.8	18.1	18.9	19.5	20.0	20.6	22.5	26.3	30.6	39.2
Petrochemical	5.7	10.9	11.7	11.9	12.1	12.3	12.3	12.3	12.3	12.3
Other Industrial	12.1	11.8	10.7	9.9	9.9	10.1	10.8	12.0	13.8	15.4
Transportation	3.1	4.8	10.1	15.5	17.2	19.0	24.3	30.1	30.2	30.2
Total End Use	**74.2**	**81.7**	**85.1**	**87.8**	**90.1**	**92.9**	**100.8**	**114.3**	**120.4**	**132.8**
Butanes										
Residential	0.6	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.6
Commercial	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.6	0.7
Petrochemical	4.3	6.8	13.1	13.2	25.7	38.1	38.1	38.1	38.1	38.1
Other Industrial	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.4	0.4	0.5
Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total End Use	**5.6**	**7.9**	**14.1**	**14.3**	**26.8**	**39.2**	**39.3**	**39.4**	**39.6**	**39.9**

- Demand data provided by NEB for 1982 are published actuals except for wood, hog fuel, pulping liquor, reprocessing fuel and pipeline transportation fuels.

Table A8-17
Primary Demand for Natural Gas Liquids – Canada
Comparison of Submittors' Views

(Petajoules)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Amoco	136	151	158	185	213	235	310	372	391	405
Dome-Low	162	212	273	350	377	389	387	335	306	N/A
Gulf	114	138	161	183	193	196	239	252	269	N/A
Imperial	155	143	181	241	287	329	311	343	329	N/A
Petro-Canada–Base	116	128	148	203	206	209	258	294	303	N/A
Shell	86	93	118	137	138	177	193	198	201	N/A
NEB	113	136	162	189	207	224	234	283	297	312

- Demand data provided by NEB for 1982 are published actuals and 1983 data were tracked to established trends published in the Statistics Canada monthly catalogues.

Table A8-18
Ethane Supply and Demand
NEB Projection

(Petajoules)

	Supply	Demand				Difference
Year	Total	Miscible[1] Fluid Reqmnts	Other Canadian Reqmnts	Net Licences Export	Total	
1983	90.5	4.7	35.2	50.6	90.5	.0
1984	116.6	8.7	48.6	48.5	105.8	10.8
1985	145.4	26.0	73.0	45.7	144.7	.7
1986	177.6	50.3	75.2	50.8	176.3	1.3
1987	191.6	68.4	75.2	42.9	186.5	5.1
1988	189.6	78.1	75.2	35.2	188.5	1.1
1989	188.3	85.1	75.2	24.2	184.5	3.8
1990	187.0	83.8	75.2	14.2	173.2	13.8
1991	184.3	83.1	75.2	11.2	169.5	14.8
1992	181.6	81.1	75.2	5.2	161.5	20.1
1993	176.2	75.7	75.2	1.9	152.8	23.4
1994	170.9	72.4	75.2	.0	147.6	23.3
1995	164.8	56.3	108.2	.0	164.5	.3
1996	160.8	44.3	115.2	.0	159.5	1.3
1997	155.5	35.5	115.2	.0	150.7	4.8
1998	149.4	21.4	115.2	.0	136.6	12.8
1999	138.7	10.1	115.2	.0	125.3	13.4
2000	128.0	.0	115.2	.0	115.2	12.8
2001	124.6	.0	115.2	.0	115.2	9.4
2002	117.3	.0	115.2	.0	115.2	2.1
2003	117.3	.0	115.2	.0	115.2	2.1
2004	117.9	.0	115.2	.0	115.2	2.7
2005	117.9	.0	115.2	.0	115.2	2.7

(1) Miscible fluid requirements are net requirements after accounting for reproduced fluids from hydrocarbon miscible projects.

Table A8-19
Propane Supply and Demand
NEB Projection

(Petajoules)

	Supply	Demand				Difference
Year	Total[1]	Miscible[2] Fluid Reqmnts	Other[1] Canadian Reqmnts	Net Licences Export	Total	
1983	174.2	16.8	81.7	7.8	106.3	67.9
1984	175.2	25.2	85.1	7.4	117.7	57.5
1985	186.4	35.4	87.8	7.4	130.6	55.8
1986	196.6	50.3	90.1	7.2	147.6	49.0
1987	216.2	65.2	92.9	6.2	164.3	51.9
1988	220.8	75.5	95.4	7.3	178.2	42.6
1989	227.4	79.2	98.1	7.4	184.7	42.7
1990	237.6	78.3	100.8	6.7	185.8	51.8
1991	232.0	77.3	103.5	6.7	187.5	44.5
1992	226.4	74.5	106.3	6.6	187.4	39.0
1993	220.8	69.9	109.0	6.5	185.4	35.4
1994	214.3	67.1	111.6	4.7	183.4	30.9
1995	207.8	55.0	114.3	.0	169.6	38.5
1996	202.2	42.9	115.3	.0	158.2	44.0
1997	195.7	34.5	116.4	.0	150.9	44.8
1998	188.2	21.4	117.7	.0	139.1	49.1
1999	182.6	11.2	119.1	.0	130.3	52.3
2000	176.1	.0	120.4	.0	120.4	55.7
2001	172.4	.0	122.6	.0	122.6	49.8
2002	167.7	.0	125.0	.0	125.0	42.7
2003	168.7	.0	127.4	.0	127.4	41.3
2004	171.5	.0	130.1	.0	130.1	41.4
2005	173.3	.0	132.8	.0	132.8	40.5

(1) Supply and demand are both net of energy supply industry own use for fuel.
(2) Miscible fluid requirements are net requirements after accounting for reproduced fluids from hydrocarbon miscible projects.

Table A8-20
Butanes Supply and Demand
NEB Projection

(Petajoules)

Year	Supply Total[1]	Demand Miscible[2] Fluid Reqmnts	Demand Other[1] Canadian Reqmnts	Demand Total	Difference
1983	126.4	9.4	45.3	54.7	71.7
1984	126.4	12.5	49.6	62.1	64.3
1985	133.7	16.7	48.6	65.3	68.4
1986	138.9	21.9	60.3	82.2	56.7
1987	151.5	26.1	72.0	98.1	53.4
1988	153.6	28.2	71.5	99.7	53.9
1989	158.8	29.2	71.4	100.6	58.2
1990	163.0	28.2	71.3	99.5	63.5
1991	158.8	27.1	71.5	98.6	60.2
1992	154.6	26.1	71.7	97.8	56.8
1993	151.5	25.1	72.0	97.1	54.4
1994	147.3	23.0	72.2	95.2	52.1
1995	142.1	18.8	72.4	91.2	50.9
1996	137.9	14.6	72.7	87.3	50.6
1997	133.7	12.5	72.9	85.4	48.3
1998	128.5	8.4	73.1	81.5	47.0
1999	124.3	5.2	73.4	78.6	45.7
2000	120.1	.0	73.6	73.6	46.5
2001	117.0	.0	74.0	74.0	43.0
2002	114.9	.0	74.3	74.3	40.6
2003	114.9	.0	74.7	74.7	40.2
2004	116.0	.0	74.9	74.9	41.1
2005	117.0	.0	75.3	75.3	41.7

(1) Supply and demand are net of energy supply industry own use for fuel.
(2) Miscible fluid requirements are net requirements after accounting for reproduced fluids from hydrocarbon miscible projects.

Table A9-1
Historical Data – Coal Production

(Kilotonnes)

	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971
Bituminous	6622	6194	5925	6394	6550	6323	6101	6100	5245	4950	8042	9712
Subbituminous	1398	1235	1358	1501	1910	2318	2348	2416	2700	2898	3556	4015
Lignite	1969	2004	2047	1700	1809	1872	1885	1822	2041	1833	3465	2994
Total	9989	9433	9330	9595	10269	10513	10334	10338	9986	9681	15063	16721

	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
Bituminous	11359	12337	12541	15786	14389	15301	17141	18433	20151	21739	22296
Subbituminous	4450	4481	5076	5958	6409	7902	8278	9568	10542	11551	13021
Lignite	2978	3654	3485	3549	4677	5478	5058	5012	5971	6798	7494
Total	18787	20472	21102	25293	25475	28681	30477	33013	36664	40088	42811

Source: Statistics Canada

Table A9-2
Coal Resources and Reserves in Canada

(Megatonnes)

Provinces	Coal Type	Resources of Immediate Interest[1]			Resources of Future Interest[1]			Reserves[2]	
		Measured[3]	Indicated[3]	Inferred[3]	Measured	Indicated	Inferred	Coal in Mineable Seams[4]	Recov-erable[5]
Nova Scotia	Bituminous	223	543	757	3	50	128	812	445
New Brunswick	Bituminous	32	16	1	—	—	—	19	18
Ontario	Lignitic	218	—	—	—	—	—	—	—
Saskatchewan	Lignitic	1 499	2 681	3 436	161	3 913	23 512	2 121	1 697
Alberta	Subbituminous	30 000	—	102 000	—	—	198 000	1 314	918
	Bituminous	9 300	—	26 700	—	—	—	945	526
British Columbia	Lignitic	1 845	91	7 439	—	—	—	739	566
	Bituminous	7 282	9 898	44 036	—	—	—	2 537	2 098
Canada – Totals	Lignitic	3 562	2 772	10 875	161	3 913	23 512	2 860	2 263
	Subbituminous	30 000	—	102 000	—	—	198 000	1 314	918
	Bituminous	16 837	10 457	71 494	3	50	128	4 313	3 087
Canada – Total	All Types	50 399	13 229	184 369	164	3 963	221 640	8 487	6 268

(1) Source: "Coal Resources and Reserves of Canada," Energy, Mines and Resources, Report ER79-9.
Resources of immediate interest consist of coal seams that, because of favourable combinations of thickness, quality, depth and location, are considered to be of immediate interest for exploration or exploitation activities.
Resources of future interest consist of coal seams that, because of less favourable combinations of thickness, quality, depth and location, are not of immediate interest.

(2) Source: "Coal Mining in Canada: 1983," Canmet Report 83-20E, 1984.

(3) These terms denote the precision with which given quantities of resources have been estimated.

(4) Coal in mineable seams includes that portion of measured and indicated resources of immediate interest that can be considered for mining using current technology and economics, before there is any allowance for mining losses.

(5) Recoverable reserves is that portion of coal in mineable seams that could be recovered as run-of-mine or raw coal, making allowances for mining losses.

Table A9-3
Coal Production – Canada
Comparison of Submittors' Views

(Megatonnes)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Gulf	42.9	45.1	51.1	57.9	62.6	65.1	74.3	90.2	111.7	N/A
Imperial(1)	41.1	N/A	N/A	N/A	N/A	N/A	80.0	N/A	101.3	N/A
NEB	42.8	44.7	53.1	52.5	54.7	56.6	62.4	71.1	79.9	90.9

(1) The original forecast was in petajoules.
Conversion factor: 24 petajoules per megatonne.

Table A9-4
Primary Demand for Coal – Canada
Comparison of Submittors' Views

(Petajoules)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
CPA	999	N/A	N/A	N/A	N/A	N/A	1077	1305	N/A	N/A
Dome-Low	1033	1009	1113	1063	1002	1032	1084	1181	1274	N/A
Gulf	1002	961	873	903	908	898	958	1200	1542	N/A
Husky/NOVA	990	838	754	716	713	706	724	899	969	1091
Imperial	1003	1023	1047	1033	1065	1097	1139	1317	1444	N/A
Petro-Canada-Base	999	991	1128	1098	1074	1143	1320	1582	1815	N/A
Shell	989	964	928	877	897	918	986	1107	1256	N/A
Texaco	1002	980	1035	1075	1140	1189	1281	1371	N/A	N/A
NEB	1002	1018	1122	1009	1050	1086	1161	1290	1395	1557

- Demand data provided by NEB for 1982 are published actuals and 1983 data were tracked to established trends published in the Statistics Canada monthly catalogue

Table A9-5
Coal Production – Imports and Exports
NEB Projection

(Kilotonnes)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
Production	42811	44725	53084	52451	54713	56580	62420	71079	79932	90860
Imports	15481	14700	16666	13051	12967	13080	11955	12771	13193	14515
Exports	16002	17008	23000	23460	23930	24410	26000	30100	35000	40500

Table A10-1
Primary Energy Demand – Canada Comparison of Submittors' Views

(Petajoules)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	2005
CPA	9636	N/A	N/A	N/A	N/A	N/A	11130	12168	N/A	N/A
Dome – Low	9263	9046	9450	9827	10033	10220	10779	12105	13302	N/A
Gulf	9420	9402	9802	10080	10282	10402	11110	12161	13418	N/A
Husky/NOVA	9820	9569	9883	10115	10266	10498	11215	12660	14164	15813
Imperial	9701	9679	10048	10303	10505	10703	11043	11714	12121	N/A
Petro-Canada – Base	9066	8946	9425	9994	10265	10502	11304	12861	14672	N/A
Shell	9145	9116	9294	9141	9239	9370	9755	10680	11687	N/A
Texaco	7885	7548	7714	7841	7990	8147	8643	9431	N/A	N/A
NEB	9471	9538	9713	9961	10086	10295	10913	12086	13397	14603

• Demand data provided by NEB for 1982 are published actuals except for wood, waste wood and pulping liquor, reprocessing fuel and pipeline transportation fuels.

Wherever possible 1983 data were tracked to established trends published in the Statistics Canada monthly catalogues.

Table A10-2
Summary of Total Energy Demand – Canada and Regions

(Petajoules)

	1981	1982	1983	1984	1985	1990	1995	2000	2005
					Canada				
Sectoral Demand									
Residential	1297	1349	1266	1256	1237	1262	1317	1381	1461
Commercial	838	867	819	847	859	955	1074	1211	1363
Industrial	2185	2001	2030	2096	2145	2422	2745	3118	3454
Transportation – Road	1506	1397	1384	1378	1361	1301	1344	1416	1461
– Air, Rail & Marine	407	348	318	318	324	357	411	465	500
– Total	1912	1745	1701	1696	1685	1658	1754	1881	1962
Non-Energy	607	550	592	640	714	775	860	898	928
Total End Use	6840	6510	6407	6535	6639	7072	7752	8489	9168
Own Use	487	465	455	460	478	540	514	551	594
Electricity & Steam Generation	3756	3777	4093	4075	4250	4921	5701	6519	7252
Other Conversions	31	25	30	33	34	43	37	38	42
Less Electricity & Steam	1292	1306	1340	1390	1440	1663	1918	2199	2453
Primary Energy Demand	9821	9471	9645	9713	9961	10913	12086	13397	14603
Primary Demand by Fuel									
Nuclear	430	418	503	525	720	986	1156	1389	1558
Hydro	2530	2495	2687	2663	2744	3043	3552	4088	4503
Oil	3744	3344	3096	3065	3019	2838	2793	2940	3065
Natural Gas	1738	1777	1766	1812	1908	2266	2507	2780	3059
NGL – Gas Plant	32	30	49	59	62	103	117	121	132
Ethane	35	22	35	49	73	75	108	115	115
Coal	842	896	1003	1014	897	996	1206	1282	1467
Renewables	470	489	506	526	538	605	649	682	704
					Atlantic				
Sectoral Demand									
Residential	112	114	104	104	102	105	114	123	131
Commercial	54	60	55	57	58	64	71	80	90
Industrial	172	153	144	148	150	167	194	223	252
Transportation – Road	126	117	112	117	116	109	110	118	128
– Air, Rail & Marine	52	37	35	34	34	36	40	43	46
– Total	177	154	147	150	150	145	149	160	175
Non-Energy	15	12	13	14	14	16	17	18	20
Total End Use	531	493	463	472	474	497	545	605	667
Own Use	40	33	31	33	34	37	39	43	48
Electricity & Steam Generation	623	606	614	692	713	792	944	1017	1070
Other Conversions	6	1	1	1	1	1	1	1	1
Less Electricity & Steam	105	105	106	111	116	134	161	195	221
Primary Energy Demand	1095	1027	1002	1087	1105	1192	1368	1470	1566

Table A10-2 (Cont'd)

	1981	1982	1983	1984	1985	1990	1995	2000	2005
			Atlantic (Cont'd)						
Primary Demand by Fuel									
Nuclear	0	0	35	17	17	17	72	93	140
Hydro	489	470	460	501	502	510	630	630	630
Oil	470	423	358	386	396	393	289	295	312
Natural Gas	0	0	0	0	0	15	45	67	82
NGL – Gas Plant	1	1	2	2	1	3	5	6	6
Ethane	0	0	0	0	0	0	0	0	0
Coal	75	73	85	117	122	180	244	293	306
Renewables	60	60	63	65	67	75	82	88	90
			Quebec						
Sectoral Demand									
Residential	314	306	290	286	285	295	307	326	345
Commercial	174	167	159	163	166	185	206	230	255
Industrial	518	467	469	478	484	540	609	691	767
Transportation – Road	326	381	267	266	257	241	258	275	276
– Air, Rail & Marine	91	79	71	71	72	78	86	93	101
– Total	417	360	339	337	329	319	344	368	377
Non-Energy	107	89	84	81	82	88	94	100	106
Total End Use	1531	1388	1340	1345	1346	1427	1561	1715	1850
Own Use	109	103	98	99	98	101	111	122	133
Electricity & Steam Generation	1003	990	1031	1075	1133	1344	1537	1832	2099
Other Conversions	-3	-3	0	0	0	0	0	0	1
Less Electricity & Steam	434	425	437	466	487	573	663	757	842
Primary Energy Demand	2204	2053	2032	2053	2090	2300	2545	2912	3240
Primary Demand by Fuel									
Nuclear	0	0	0	47	47	47	47	47	47
Hydro	999	986	1028	1024	1082	1293	1476	1765	2031
Oil	979	847	747	705	665	603	607	635	654
Natural Gas	121	113	136	146	161	208	246	286	318
NGL – Gas Plant	8	6	9	18	20	24	27	29	31
Ethane	0	0	0	0	0	0	0	0	0
Coal	15	14	18	18	18	17	20	23	25
Renewables	83	88	93	96	98	109	122	129	134

Table A10-2 (Cont'd)

	1981	1982	1983	1984	1985	1990	1995	2000	2005
				Ontario					
Sectoral Demand									
Residential	474	475	455	449	441	447	463	480	506
Commercial	320	319	312	310	308	333	368	408	451
Industrial	795	714	747	776	797	903	1029	1169	1290
Transportation – Road	507	479	483	476	479	461	476	491	475
– Air, Rail & Marine	99	87	87	86	87	96	113	130	139
– Total	605	566	569	561	566	557	589	621	615
Non-Energy	210	170	178	193	211	210	217	224	231
Total End Use	2405	2245	2261	2289	2323	2450	2665	2902	3092
Own Use	177	163	163	163	166	176	179	190	199
Electricity & Steam Generation	1086	1100	1247	1142	1197	1411	1599	1811	1997
Other Conversions	9	13	13	14	14	15	17	19	21
Less Electricity & Steam	418	427	441	442	450	508	571	642	704
Primary Energy Demand	3258	3093	3242	3165	3250	3544	3889	4280	4605
Primary Demand by Fuel									
Nuclear	430	418	468	462	656	922	1037	1249	1371
Hydro	403	402	426	401	401	401	423	452	455
Oil	1183	1043	1010	994	986	887	906	946	952
Natural Gas	734	703	699	715	744	860	952	1050	1148
NGL – Gas Plant	13	5	21	21	23	52	55	53	56
Ethane	0	0	0	0	0	0	0	0	0
Coal	420	435	532	485	352	318	399	400	485
Renewables	75	87	86	87	89	104	118	130	139
				Manitoba					
Sectoral Demand									
Residential	54	59	55	55	54	55	54	53	53
Commercial	40	45	42	45	46	49	53	57	61
Industrial	41	35	39	42	45	53	58	63	67
Transportation – Road	64	63	65	61	59	60	64	73	82
– Air, Rail & Marine	20	17	15	16	16	17	19	21	23
– Total	83	79	80	77	75	77	83	94	104
Non-Energy	11	10	10	10	10	11	11	12	12
Total End Use	228	229	226	229	230	244	259	278	297
Own Use	25	26	26	26	27	33	28	28	30
Electricity & Steam Generation	159	158	229	213	213	213	254	254	254
Other Conversions	0	0	0	0	0	0	0	0	0
Less Electricity & Steam	49	52	53	55	56	63	70	74	77
Primary Energy Demand	362	361	428	413	414	428	471	486	504

Table A10-2 (Cont'd)

	1981	1982	1983	1984	1985	1990	1995	2000	2005
			Manitoba (Cont'd)						
Primary Demand by Fuel									
Nuclear	0	0	0	0	0	0	0	0	0
Hydro	151	153	226	212	212	212	252	252	252
Oil	115	113	111	106	103	101	104	114	125
Natural Gas	75	80	75	79	83	95	93	97	102
NGL – Gas Plant	3	3	3	3	2	3	4	4	4
Ethane	0	0	0	0	0	0	0	0	0
Coal	9	6	6	5	5	5	5	5	5
Renewables	9	6	7	8	10	13	14	15	16
			Saskatchewan						
Sectoral Demand									
Residential	69	77	72	75	75	74	74	76	77
Commercial	29	34	32	33	34	40	46	52	59
Industrial	75	66	71	75	79	94	111	130	146
Transportation – Road	84	83	85	89	87	84	85	92	102
– Air, Rail & Marine	10	9	8	8	8	9	11	12	13
– Total	94	91	93	97	96	94	96	103	115
Non-Energy	9	14	13	13	13	14	15	16	17
Total End Use	277	282	281	294	297	316	342	377	414
Own Use	37	40	39	43	48	62	45	46	51
Electricity & Steam Generation	120	131	126	142	148	170	198	227	246
Other Conversions	0	0	0	0	0	0	0	0	0
Less Electricity & Steam	36	37	39	42	44	50	58	66	73
Primary Energy Demand	399	416	407	436	440	498	528	585	638
Primary Demand by Fuel									
Nuclear	0	0	0	0	0	0	0	0	0
Hydro	33	29	24	29	29	40	41	41	65
Oil	147	147	144	149	148	143	145	156	170
Natural Gas	124	132	125	127	135	164	162	177	196
NGL – Gas Plant	1	2	1	2	2	3	3	4	4
Ethane	0	0	0	0	0	0	0	0	0
Coal	84	96	101	118	123	133	160	188	183
Renewables	11	10	12	13	14	16	17	19	21

Table A10-2 (Cont'd)

	1981	1982	1983	1984	1985	1990	1995	2000	2005
					Alberta				
Sectoral Demand									
Residential	155	192	172	167	161	166	176	188	205
Commercial	126	144	129	143	148	174	203	236	276
Industrial	185	175	165	169	172	199	236	279	320
Transportation – Road	213	204	207	204	195	178	176	188	202
– Air, Rail & Marine	50	47	44	44	45	49	57	66	70
– Total	264	251	250	248	240	227	233	254	272
Non-Energy	223	223	260	295	347	376	443	463	474
Total End Use	952	986	976	1022	1069	1141	1291	1419	1546
Own Use	48	51	50	51	53	64	58	61	66
Electricity & Steam Generation	309	331	321	310	323	395	467	550	637
Other Conversions	17	16	16	18	19	26	18	17	20
Less Electricity & Steam	92	99	102	104	108	131	156	184	213
Primary Energy Demand	1235	1284	1261	1298	1357	1495	1678	1863	2056
Primary Demand by Fuel									
Nuclear	0	0	0	0	0	0	0	0	0
Hydro	22	17	16	17	17	17	57	152	152
Oil	407	379	374	374	370	362	374	405	433
Natural Gas	514	565	550	558	590	664	724	780	852
NGL – Gas Plant	5	10	8	8	9	12	14	16	19
Ethane	35	22	35	49	73	75	108	115	115
Coal	233	271	257	279	275	340	375	369	458
Renewables	20	20	22	23	23	25	26	27	27
					British Columbia & Territories				
Sectoral Demand									
Residential	119	126	117	119	119	121	128	136	144
Commercial	94	99	90	97	99	110	127	147	171
Industrial	399	390	396	410	417	466	510	563	614
Transportation – Road	186	171	165	166	168	168	175	181	196
– Air, Rail & Marine	86	71	57	59	61	72	85	100	109
– Total	272	243	222	225	229	239	260	281	304
Non-Energy	32	31	34	35	36	61	64	66	69
Total End Use	917	888	859	885	899	997	1089	1193	1302
Own Use	52	49	49	47	52	67	55	61	67
Electricity & Steam Generation	456	460	526	501	522	595	702	829	949
Other Conversions	2	-1	0	0	0	0	0	0	0
Less Electricity & Steam	159	161	162	171	178	203	238	282	324
Primary Energy Demand	1268	1235	1272	1262	1296	1456	1607	1801	1994

Table A10-2 (Cont'd)

	1981	1982	1983	1984	1985	1990	1995	2000	2005
			British Columbia and Territories (Cont'd)						
Primary Demand by Fuel									
Nuclear	0	0	0	0	0	0	0	0	0
Hydro	434	438	508	481	501	571	673	797	918
Oil	442	392	350	351	352	349	366	391	420
Natural Gas	171	183	181	188	195	261	285	324	362
NGL – Gas Plant	2	2	5	6	6	7	9	10	11
Ethane	0	0	0	0	0	0	0	0	0
Coal	7	2	4	3	4	3	4	4	5
Renewables	212	219	224	234	238	265	270	275	278

Table A10-3
Total Energy Balance – Canada 1982

(Petajoules)

	Elec-tricity	Oil	Natural Gas	Ethane	Propane and Butanes	Coal, Coke CK Oven Gas	Steam	Wood	Other Renew-able	Hydro	Nuclear	Total
Sector Demand												
Residential	357	372	484	0	35	4	0	97	0	0	0	1349
Commercial	279	174	393	0	19	1	1	0	0	0	0	867
Petrochemical	0	108	209	22	10	0	0	0	0	0	0	349
Other Industrial	490	371	499	0	13	200	62	365	0	0	0	2001
Transportation	3	1739	0	0	3	0	0	0	0	0	0	1745
Road	3	1392	0	0	3	0	0	0	0	0	0	1397
Rail	0	84	0	0	0	0	0	0	0	0	0	84
Air	0	152	0	0	0	0	0	0	0	0	0	152
Marine	0	112	0	0	0	0	0	0	0	0	0	112
Non-Energy Use	0	201	0	0	0	0	0	0	0	0	0	201
Total End Use	1129	2965	1585	22	80	205	63	462	0	0	0	6510
Own Use & Conversions												
Energy Supply Industry	114	225	115	0	11	0	0	0	0	0	0	465
Electricity Generation	0	85	61	0	0	673	0	28	0	2495	374	3716
Steam Production	0	9	0	0	0	9	0	0	0	0	44	61
Other Conversions	0	0	16	0	0	9	0	0	0	0	0	25
Total Own Use & Conversions	114	318	192	0	11	691	0	28	0	2495	418	4267
Less Non-Primary Demand	1243	0	0	0	0	0	63	0	0	0	0	1306
Total Primary Demand	0	3283	1777	22	91	896	0	489	0	2495	418	9471
Fuels For Electricity Exports[1]	0	7	0	0	0	106	0	0	0	236	0	349
Sub-Total	0	3290	1777	22	91	1002		489		2731	418	9820
Exports of Primary Energy	0	558	850	55	185	477		0		0	0	2125
Total Disposition	0	3848	2627	77	276	1479		489		2731	418	11945
Energy Imports	0	773	0	0	0	494		0		0	0	1267
Energy Production	0	3052	2622	78	227	1027		489		2731	418	10644
Total Primary Supply	0	3825	2622	78	227	1521		489		2731	418	11911

[1] Final adjusted estimates for this item for 1982-2005 are found in Table A5-7, Appendix 5.

Table A10-3
Total Energy Balance – Canada 1983

(Petajoules)

	Electricity	Oil	Natural Gas	Ethane	Propane and Butanes	Coal, Coke CK Oven Gas	Steam	Wood	Other Renewable	Hydro	Nuclear	Total
Sector Demand												
Residential	368	309	449	0	37	2	0	100	0	0	0	1266
Commercial	282	144	372	0	18	1	1	0	0	0	0	819
Petrochemical	0	98	233	35	18	0	0	0	0	0	0	384
Other Industrial	508	321	520	0	12	230	56	384	0	0	0	2030
Transportation	3	1694	0	0	5	0	0	0	0	0	0	1701
Road	3	1376	0	0	5	0	0	0	0	0	0	1384
Rail	0	78	0	0	0	0	0	0	0	0	0	78
Air	0	146	0	0	0	0	0	0	0	0	0	146
Marine	0	93	0	0	0	0	0	0	0	0	0	93
Non-Energy Use	0	208	0	0	0	0	0	0	0	0	0	208
Total End Use	1161	2773	1573	35	90	233	57	484	0	0	0	6407
Own Use & Conversions												
Energy Supply Industry	121	210	122	0	11	0	0	0	0	0	0	455
Electricity Generation	0	54	65	0	0	635	0	16	7	2687	451	3915
Steam Production	0	6	0	0	0	14	0	0	0	0	52	72
Other Conversions	0	0	16	0	0	14	0	0	0	0	0	30
Total Own Use & Conversions	121	270	193	0	11	770	0	16	7	2687	503	4578
Less Non-Primary Demand	1282	0	0	0	0	0	57	0	0	0	0	1340
Total Primary Demand	0	3044	1766	35	101	896	0	499	7	2687	503	9538
Fuels For Electricity Exports	0	0	0	0	0	122	0	0	0	241	16	379
Sub-Total	0	3044	1766	35	101	1018		506		2928	519	9917
Exports of Primary Energy	0	835	751	51	147	408		0		0	0	2192
Total Disposition	0	3879	2517	86	248	1426		506		2928	519	12109
Energy Imports	0	611	0	0	0	344		0		0	0	955
Energy Production	0	3225	2516	86	274	1077		506		2928	519	11131
Total Primary Supply	0	3836	2516	86	274	1421		506		2928	519	12086

Table A10-3
Total Energy Balance – Canada 1984

(Petajoules)

	Electricity	Oil	Natural Gas	Ethane	Propane and Butanes	Coal, Coke CK Oven Gas	Steam	Wood	Other Renewable	Hydro	Nuclear	Total
Sector Demand												
Residential	378	285	453	0	34	2	0	103	0	0	0	1256
Commercial	292	135	397	0	19	1	1	0	0	0	0	847
Petrochemical	0	102	252	49	25	0	0	0	0	0	0	427
Other Industrial	549	299	549	0	11	247	41	401	0	0	0	2096
Transportation	3	1683	0	0	10	0	0	0	0	0	0	1696
Road	3	1365	0	0	10	0	0	0	0	0	0	1378
Rail	0	80	0	0	0	0	0	0	0	0	0	80
Air	0	142	0	0	0	0	0	0	0	0	0	142
Marine	0	96	0	0	0	0	0	0	0	0	0	96
Non-Energy Use	0	213	0	0	0	0	0	0	0	0	0	213
Total End Use	1222	2718	1651	49	99	251	43	503	0	0	0	6535
Own Use & Conversions												
Energy Supply Industry	125	206	116	0	13	0	0	0	0	0	0	460
Electricity Generation	0	82	28	0	0	737	0	16	7	2663	490	4022
Steam Production	0	6	0	0	0	12	0	0	0	0	36	53
Other Conversions	0	0	18	0	0	15	0	0	0	0	0	33
Total Own Use & Conversions	125	294	161	0	13	763	0	16	7	2663	525	4568
Less Non-Primary Demand	1348	0	0	0	0	0	43	0	0	0	0	1390
Total Primary Demand	0	3011	1812	49	113	1014	0	519	7	2663	525	9713
Fuels For Electricity Exports	0	6	0	0	0	108	0	0	0	364	30	508
Sub-Total	0	3017	1812	49	113	1122		526		3027	555	10221
Exports of Primary Energy	0	1131	782	49	129	552		0		0	0	2643
Total Disposition	0	4148	2594	98	242	1674		526		3027	555	12864
Energy Imports	0	531	0	0	0	400		0		0	0	931
Energy Production	0	3505	2592	97	264	1274		526		3027	555	11840
Total Primary Supply	0	4036	2592	97	264	1674		526		3027	555	12771

Table A10-3
Total Energy Balance – Canada 1985

(Petajoules)

	Elec-tricity	Oil	Natural Gas	Ethane	Propane and Butanes	Coal, Coke CK Oven Gas	Steam	Wood	Other Renew-able	Hydro	Nuclear	Total
Sector Demand												
Residential	389	260	449	0	31	2	0	106	0	0	0	1237
Commercial	303	125	408	0	20	1	1	0	0	0	0	859
Petrochemical	0	119	279	73	25	0	0	0	0	0	0	496
Other Industrial	577	278	584	0	10	254	34	409	0	0	0	2145
Transportation	3	1661	6	0	15	0	0	0	0	0	0	1685
Road	3	1337	6	0	15	0	0	0	0	0	0	1361
Rail	0	82	0	0	0	0	0	0	0	0	0	82
Air	0	141	0	0	0	0	0	0	0	0	0	141
Marine	0	101	0	0	0	0	0	0	0	0	0	101
Non-Energy Use	0	218	0	0	0	0	0	0	0	0	0	218
Total End Use	1272	2660	1725	73	102	257	35	515	0	0	0	6639
Own Use & Conversions												
Energy Supply Industry	132	201	130	0	14	0	0	0	0	0	0	478
Electricity Generation	0	98	34	0	0	613	0	17	7	2744	693	4206
Steam Production	0	6	0	0	0	12	0	0	0	0	27	44
Other Conversions	0	0	19	0	0	15	0	0	0	0	0	34
Total Own Use & Conversions	'132	305	183	0	14	640	0	17	7	2744	720	4762
Less Non-Primary Demand	1404	0	0	0	0	0	35	0	0	0	0	1440
Total Primary Demand	0	2965	1908	73	116	897	0	531	7	2744	721	9961
Fuels For Electricity Exports	0	6	0	0	0	112	0	0	0	381	29	528
Sub-Total	0	2971	1908	73	116	1109		538		3125	750	10490
Exports of Primary Energy	0	924	996	46	132	563		0		0	0	2661
Total Disposition	0	3895	2904	119	248	1572		538		3125	750	13151
Energy Imports	0	659	0	0	0	313		0		0	0	972
Energy Production	0	3385	2901	119	268	1259		538		3125	750	12345
Total Primary Supply	0	4044	2901	119	268	1572		538		3125	750	13317

Table A10-3
Total Energy Balance – Canada 1986

(Petajoules)

	Electricity	Oil	Natural Gas	Ethane	Propane and Butanes	Coal, Coke CK Oven Gas	Steam	Wood	Other Renewable	Hydro	Nuclear	Total
Sector Demand												
Residential	399	242	444	0	31	2	0	109	1	0	0	1228
Commercial	311	119	420	0	20	1	1	0	1	0	0	875
Petrochemical	0	97	290	75	38	0	0	0	0	0	0	500
Other Industrial	597	269	612	0	10	254	32	415	2	0	0	2191
Transportation	3	1633	8	0	17	0	0	0	0	0	0	1661
Road	3	1305	8	0	17	0	0	0	0	0	0	1333
Rail	0	83	0	0	0	0	0	0	0	0	0	83
Air	0	141	0	0	0	0	0	0	0	0	0	141
Marine	0	105	0	0	0	0	0	0	0	0	0	105
Non-Energy Use	0	223	0	0	0	0	0	0	0	0	0	223
Total End Use	1310	2584	1774	75	117	257	34	523	4	0	0	6678
Own Use & Conversions												
Energy Supply Industry	138	194	139	0	15	0	0	0	0	0	0	486
Electricity Generation	0	76	53	0	0	599	0	18	8	2841	731	4325
Steam Production	0	5	0	0	0	11	0	0	0	0	26	42
Other Conversions	0	0	20	0	0	15	0	0	0	0	0	35
Total Own Use & Conversions	138	275	212	0	15	625	0	18	8	2841	757	4889
Less Non-Primary Demand	1448	0	0	0	0	0	34	0	0	0	0	1481
Total Primary Demand	0	2859	1986	75	132	883	0	541	11	2841	757	10086
Fuels For Electricity Exports	0	5	0	0	0	167	0	0	0	386	30	588
Sub-Total	0	2864	1986	75	132	1050		552		3227	787	10673
Exports of Primary Energy	0	818	1133	51	113	574		0		0	0	2689
Total Disposition	0	3682	3119	126	245	1624		552		3227	787	13362
Energy Imports	0	495	0	0	0	311		0		0	0	806
Energy Production	0	3212	3117	126	263	1313		552		3227	787	12597
Total Primary Supply	0	3707	3117	126	263	1624		552		3227	787	13403

Table A10-3
Total Energy Balance – Canada 1987

(Petajoules)

	Electricity	Oil	Natural Gas	Ethane	Propane and Butanes	Coal, Coke CK Oven Gas	Steam	Wood	Other Renewable	Hydro	Nuclear	Total
Sector Demand												
Residential	412	227	450	0	31	2	0	110	3	0	0	1234
Commercial	321	114	433	0	21	1	1	0	2	0	0	894
Petrochemical	0	76	305	75	50	0	0	0	0	0	0	506
Other Industrial	618	269	636	0	10	261	31	421	3	0	0	2248
Transportation	3	1617	10	0	19	0	0	0	0	0	0	1649
Road	3	1279	10	0	19	0	0	0	0	0	0	1312
Rail	0	85	0	0	0	0	0	0	0	0	0	85
Air	0	144	0	0	0	0	0	0	0	0	0	144
Marine	0	109	0	0	0	0	0	0	0	0	0	109
Non-Energy Use	0	228	0	0	0	0	0	0	0	0	0	228
Total End Use	1353	2531	1833	75	132	264	32	531	8	0	0	6759
Own Use & Conversions												
Energy Supply Industry	144	190	166	0	17	0	0	0	0	0	0	517
Electricity Generation	0	103	46	0	0	620	0	19	8	2885	787	4469
Steam Production	0	5	0	0	0	10	0	0	0	0	25	40
Other Conversions	0	0	24	0	0	16	0	0	0	0	0	40
Total Own Use & Conversions	144	299	236	0	17	646	0	19	8	2885	812	5065
Less Non-Primary Demand	1497	0	0	0	0	0	32	0	0	0	0	1529
Total Primary Demand	0	2830	2068	75	149	910	0	550	16	2885	812	10295
Fuels For Electricity Exports	0	0	0	0	0	175	0	0	0	394	30	599
Sub-Total	0	2830	2068	75	149	1085		566		3279	842	10894
Exports of Primary Energy	0	763	1523	43	112	586		0		0	0	3027
Total Disposition	0	3593	3591	118	261	1671		566		3279	842	13921
Energy Imports	0	518	0	0	0	314		0		0	0	832
Energy Production	0	3100	3588	118	276	1358		566		3279	842	13127
Total Primary Supply	0	3618	3588	118	276	1672		566		3279	842	13959

Table A10-3
Total Energy Balance – Canada 1990

(Petajoules)

	Elec-tricity	Oil	Natural Gas	Ethane	Propane and Butanes	Coal, Coke CK Oven Gas	Steam	Wood	Other Renew-able	Hydro	Nuclear	Total
Sector Demand												
Residential	449	184	475	0	31	2	0	114	7	0	0	1262
Commercial	349	97	476	0	23	2	1	0	7	0	0	955
Petrochemical	0	76	331	75	50	0	0	0	0	0	0	533
Other Industrial	684	269	713	0	11	273	25	438	9	0	0	2422
Transportation	4	1613	17	0	24	0	0	0	0	0	0	1658
Road	4	1256	17	0	24	0	0	0	0	0	0	1301
Rail	0	89	0	0	0	0	0	0	0	0	0	89
Air	0	148	0	0	0	0	0	0	0	0	0	148
Marine	0	120	0	0	0	0	0	0	0	0	0	120
Non-Energy Use	0	242	0	0	0	0	0	0	0	0	0	242
Total End Use	1486	2482	2012	75	140	277	26	552	22	0	0	7072
Own Use & Conversions												
Energy Supply Industry	151	186	184	0	19	0	0	0	0	0	0	540
Electricity Generation	0	112	42	0	0	695	0	22	9	3043	966	4889
Steam Production	0	2	3	0	0	7	0	0	0	0	20	32
Other Conversions	0	0	26	0	0	17	0	0	0	0	0	43
Total Own Use & Conversions	151	301	254	0	19	719	0	22	9	3043	986	5504
Less Non-Primary Demand	1637	0	0	0	0	0	26	0	0	0	0	1663
Total Primary Demand	0	2783	2266	75	159	996	0	574	31	3043	986	10913
Fuels For Electricity Exports	0	0	0	0	0	165	0	0	0	245	31	441
Sub-Total	0	2783	2266	75	159	1161		605		3288	1017	11354
Exports of Primary Energy	0	545	1844	14	122	622		0		0	0	3147
Total Disposition	0	3328	4110	89	281	1783		605		3288	1017	14501
Energy Imports	0	527	0	0	0	287		0		0	0	814
Energy Production	0	2825	4096	89	294	1496		605		3288	1017	13710
Total Primary Supply	0	3352	4096	89	294	1783		605		3288	1017	14524

Table A10-3
Total Energy Balance – Canada 1995

(Petajoules)

	Elec-tricity	Oil	Natural Gas	Ethane	Propane and Butanes	Coal, Coke CK Oven Gas	Steam	Wood	Other Renew-able	Hydro	Nuclear	Total
Sector Demand												
Residential	501	143	496	0	34	2	0	120	21	0	0	1317
Commercial	401	79	549	0	27	2	1	0	15	0	0	1074
Petrochemical	0	76	360	108	50	0	0	0	0	0	0	595
Other Industrial	812	258	877	0	12	308	22	442	15	0	0	2747
Transportation	6	1687	31	0	30	0	0	0	0	0	0	1754
Road	6	1276	31	0	30	0	0	0	0	0	0	1344
Rail	0	97	0	0	0	0	0	0	0	0	0	97
Air	0	176	0	0	0	0	0	0	0	0	0	176
Marine	0	138	0	0	0	0	0	0	0	0	0	138
Non-Energy Use	0	266	0	0	0	0	0	0	0	0	0	266
Total End Use	1720	2509	2313	108	154	311	24	562	51	0	0	7752
Own Use & Conversions												
Energy Supply Industry	174	185	134	0	21	1	0	0	0	0	0	514
Electricity Generation	0	39	41	0	0	870	0	24	11	3552	1135	5671
Steam Production	0	2	1	0	0	6	0	0	0	0	21	29
Other Conversions	0	0	18	0	0	19	0	0	0	0	0	37
Total Own Use & Conversions	174	226	194	0	21	894	0	24	11	3552	1156	6251
Less Non-Primary Demand	1894	0	0	0	0	0	24	0	0	0	0	1918
Total Primary Demand	0	2735	2507	108	175	1206	0	586	62	3552	1156	12086
Fuels For Electricity Exports	0	0	0	0	0	85	0	0	0	189	73	347
Sub-Total	0	2735	2507	108	175	1291		648		3741	1229	12434
Exports of Primary Energy	0	458	367	0	89	686		0		0	0	1600
Total Disposition	0	3193	2874	108	264	1977		648		3741	1229	14034
Energy Imports	0	38	0	0	0	307		0		0	0	345
Energy Production	0	3211	2842	108	276	1670		648		3741	1229	13725
Total Primary Supply	0	3249	2842	108	276	1977		648		3741	1229	14070

Table A10-3
Total Energy Balance – Canada 2000

(Petajoules)

	Elec-tricity	Oil	Natural Gas	Ethane	Propane and Butanes	Coal, Coke CK Oven Gas	Steam	Wood	Other Renew-able	Hydro	Nuclear	Total
Sector Demand												
Residential	551	133	514	0	34	2	0	120	28	0	0	1381
Commercial	458	68	625	0	31	2	1	0	26	0	0	1211
Petrochemical	0	76	367	115	50	0	0	0	0	0	0	609
Other Industrial	956	268	1044	0	14	345	23	445	23	0	0	3118
Transportation	13	1796	41	0	30	0	0	0	0	0	0	1881
Road	13	1332	41	0	30	0	0	0	0	0	0	1416
Rail	0	106	0	0	0	0	0	0	0	0	0	106
Air	0	201	0	0	0	0	0	0	0	0	0	201
Marine	0	157	0	0	0	0	0	0	0	0	0	157
Non-Energy Use	0	290	0	0	0	0	0	0	0	0	0	290
Total End Use	1977	2630	2591	115	160	349	24	565	77	0	0	8489
Own Use & Conversions												
Energy Supply Industry	197	194	137	0	22	1	0	0	0	0	0	551
Electricity Generation	0	52	34	0	0	905	0	27	13	4088	1368	6488
Steam Production	0	2	1	0	0	6	0	0	0	0	21	30
Other Conversions	0	0	17	0	0	21	0	0	0	0	0	38
Total Own Use & Conversions	197	249	189	0	22	933	0	27	13	4088	1389	7107
Less Non-Primary Demand	2174	0	0	0	0	0	24	0	0	0	0	2199
Total Primary Demand	0	2879	2780	115	182	1282	0	592	90	4088	1389	13397
Fuels For Electricity Exports	0	0	0	0	0	114	0	0	0	147	63	324
Sub-Total	0	2879	2780	115	182	1396		682		4235	1452	13721
Exports of Primary Energy	0	479	167	0	102	758		0		0	0	1506
Total Disposition	0	3358	2947	115	284	2154		682		4235	1452	15227
Energy Imports	0	268	0	0	0	317		0		0	0	585
Energy Production	0	3132	2894	115	296	1836		682		4235	1452	14642
Total Primary Supply	0	3400	2894	115	296	2153		682		4235	1452	15227

Table A10-3
Total Energy Balance – Canada 2005

(Petajoules)

	Elec-tricity	Oil	Natural Gas	Ethane	Propane and Butanes	Coal, Coke CK Oven Gas	Steam	Wood	Other Renew-able	Hydro	Nuclear	Total
Sector Demand												
Residential	589	133	548	0	36	2	0	120	32	0	0	1461
Commercial	518	59	703	0	40	2	1	0	39	0	0	1363
Petrochemical	0	76	372	115	50	0	0	0	0	0	0	614
Other Industrial	1091	291	1192	0	16	371	21	445	28	0	0	3454
Transportation	13	1877	41	0	30	0	0	0	0	0	0	1962
Road	13	1377	41	0	30	0	0	0	0	0	0	1461
Rail	0	109	0	0	0	0	0	0	0	0	0	109
Air	0	217	0	0	0	0	0	0	0	0	0	217
Marine	0	174	0	0	0	0	0	0	0	0	0	174
Non-Energy Use	0	314	0	0	0	0	0	0	0	0	0	314
Total End Use	2211	2750	2857	115	173	376	22	565	99	0	0	9168
Own Use & Conversions												
Energy Supply Industry	220	201	149	0	24	1	0	0	0	0	0	594
Electricity Generation	0	48	32	0	0	1063	0	27	13	4503	1538	7225
Steam Production	0	2	1	0	0	5	0	0	0	0	20	28
Other Conversions	0	0	20	0	0	22	0	0	0	0	0	42
Total Own Use & Conversions	220	250	202	0	24	1091	0	27	13	4503	1558	7888
Less Non-Primary Demand	2431	0	0	0	0	0	22	0	0	0	0	2453
Total Primary Demand	0	3001	3059	115	197	1467	0	592	112	4503	1558	14603
Fuels For Electricity Exports	0	0	0	0	0	91	0	0	0	78	65	234
Sub-Total	0	3001	3059	115	197	1558		704		4580	1623	14837
Exports of Primary Energy	0	559	0	0	82	837		0		0	0	1478
Total Disposition	0	3560	3059	115	279	2395		704		4580	1623	16315
Energy Imports	0	578	0	0	0	348		0		0	0	926
Energy Production	0	3044	2986	115	290	2045		704		4580	1623	15387
Total Primary Supply	0	3622	2986	115	290	2393		704		4580	1623	16313

WORD INDEX

Air transportation 20,29,31,32
Alberta 5, 19, 41, 42, 47, 49, 51, 53, 55, 58, 59, 61-63, 69, 77, 85, 87, 88, 90, 93, 94, 106
Alsands 76
Alternative energy
  see Cost
Ammonia 19
Appliances 13-15, 31
Arctic 55, 58, 69, 78
Asphalt 13, 17, 19, 83
Atlantic provinces 11, 25, 28, 29, 66, 67, 83, 84, 93
Automobiles 19
Aviation fuels 58, 80

Beaufort Sea 69, 78, 84, 89, 106
Beyond economic reach 61, 62
Biomass 3, 26, 54, 106
Bitumen 69, 75-77, 83, 106
British Columbia 5, 25, 33-35, 39, 42, 47, 51, 55, 58, 61, 62, 64, 83, 87, 93, 106
Butanes 82, 83, 87-92
  see also Exports

California 62, 63
Carbon dioxide 74, 75, 90
Coal 3, 29, 31, 35, 40, 42-47, 49, 51, 53, 54, 63, 64, 69, 93-98, 100
  see also Export, Reserves
Cogeneration 17
Commercial sector
  see Sector, Commercial
Compressed natural gas
  see Natural gas for vehicles
Connection schedule 61, 62
Conservation 6, 13-17, 22, 23, 26, 32, 34, 80, 105
Costs
  - of Alternative energy 25, 26
  - Refinery acquisition 5, 6, 82, 84
  - Supply 26, 57, 70, 106
  - Upgrading 77
Crude Oil
  see Exports, Price, Reserves

Deferred reserves
  see Reserves, Deferred
Deliverability 3, 55, 59-63, 66, 107
Diesel fuel 20, 80, 82
Drilling 56-58, 60, 66, 71, 73, 74, 79

East Coast offshore 11, 58, 69, 78, 84
Economic activity 1, 2, 5-13, 17, 18, 22, 23, 28, 66, 105
Economic growth 7, 8, 10, 15, 21, 22, 32, 35, 36
Electricity 3, 6, 13, 17, 25, 28-36, 39-54, 62, 65, 79, 83, 94, 97, 98, 101, 103, 105, 106, 107
  see also Exports, Price
Energy efficiency 14-16, 20
Energy intensities 2, 13-17, 20, 22, 105
Enhanced oil recovery 71, 73-76, 78, 101
Environment 18, 19, 31, 94
Established reserves
  see Reserves, Established
Ethane 19, 87-90
Ethylene 19, 90
Exploration 11, 55, 69, 73, 74, 78
Exports
  Butanes 90, 91
  Coal 93-95, 100, 101, 102, 106
  Crude oil 69, 71, 76, 80, 82-85, 101, 102
  Electricity 40, 42-49, 51, 52, 98, 101, 102, 105, 107
  Natural gas 3, 55, 57, 62-66, 101, 105, 107
  Natural gas liquids 87, 88, 90, 98, 101, 102
  Propane 90, 91

Forestry 16
Frontier areas 55, 57-59, 69, 78, 79

Gasification 26
Gasoline 20, 80, 89, 90
Generating capacity 3, 26, 30, 40-50, 54, 101, 107
Geological potential 2, 3, 57, 58, 73, 78, 106
Gross national product 1, 5, 8, 10, 20, 105

Heavy fuel oil 29, 31, 34, 53, 82, 83
Hibernia 60, 78, 106
Household 9, 13-15, 19, 28, 30, 34
Hydroelectricity 25, 29, 31, 42-49, 49, 52, 53

Imports 62, 64, 69, 71, 80, 82-84, 94, 95, 100, 102
Income 7, 14, 15, 19
Industrial chemicals 16, 17
Industrial sector
  see Sector, Industrial
Infill drilling 71, 74, 79
In situ recovery 69, 74-77
Interprovincial Pipe Line Limited 84
Interfuel competition 28, 29, 31, 65, 80, 106
Iron and steel 10, 16, 94

Labour force 8, 9
Light crude oil 3, 71, 81, 83-85, 88, 106
Light fuel oil 80
Liquefaction 26, 69
Liquefied petroleum gas 79
Load factor 20, 39, 64
Loss 31, 39, 41, 63, 64, 80, 94, 97, 98

Mackenzie Delta 55, 58, 60, 69, 78, 84, 89, 106
Manitoba 25, 31, 40-42, 46, 47, 51, 63, 93
Marine 20

Methanol 19, 26
Middle distillate 82
Mining 10, 16, 17, 48, 69, 76, 77, 78, 93
Miscible, Floods, Fluids 74-76, 89, 90
Model 3, 20, 75
Municipal waste 25, 26

Natural gas
- Demand 18, 19, 53, 65-67
- Supply 52-62, 87, 88
- *see Exports, Price, Reserves*

Natural gas for vehicles 20, 66
Natural gas liquids 3, 13, 18, 19, 35, 74, 75, 87-92, 97
- *see Exports*

Netback 55, 60
New Brunswick 29, 40, 43-45, 51, 53, 93
Newfoundland 29, 42, 45, 53, 78
Non-Energy sector
- *See Sector, Non-Energy*

Northwest Territories 25, 33, 35, 48, 55, 71
Nova Scotia 28, 43, 44, 53, 93
Nuclear power 31, 40, 42-49, 51-53, 63, 97, 98, 100, 103

Oil sands 11, 69, 70, 75-77, 85, 106, 107
Ontario 5, 19, 25, 26, 28, 30, 31, 41, 45, 46, 51, 53, 55, 57, 82-84, 93-95
OPEC 6-8
Own use 79, 89, 94, 97

Peak load 39, 49
Peat 26, 28
Pentanes plus 69, 75, 76, 85, 87-90
Petrochemicals 13, 16-19, 65, 66, 90, 91, 101
Plasma arc technology 94
Policy 1, 5, 7-10, 13, 15, 18, 26, 33, 36, 62, 65, 76, 79, 94, 105, 107
Population 8, 9, 11, 13, 15, 51, 63, 102, 105
Portland-Montreal Pipeline 84
Price
- Crude Oil 5, 26, 73, 74, 76, 77, 80, 107
- Electricity 5, 6, 26, 29, 31, 33, 34, 82, 105
- Field Gate 57
- Natural Gas 5, 26, 29, 31, 33-35, 55, 57, 59, 62, 63, 105-107
- Refined petroleum products 5, 18
- Wholesale 1
- World oil 1, 2, 3, 5-8, 26, 35, 71, 75, 79, 93, 94, 105, 107

Primary energy 3, 39, 51, 52, 97, 98, 100, 103
Prince Edward Island 41, 43, 44, 53
Productive capacity 7, 8, 69, 71, 73-75, 79, 101
Productivity 9, 15
Propane 20, 74, 87-91, 106
- *see also Exports*

Pulp and paper 10, 16, 17, 26, 27, 29
Pulping liquor 27, 34, 54

Quebec 5, 25, 28-30, 39, 42-46, 51, 53, 82-84

Rail transportation 20, 94
Refineries 3, 5, 6, 31, 76, 79, 80, 82, 83, 85, 87-90
Refined petroleum products 13, 26, 80, 82, 107
Refinery feedstocks 3, 69, 77, 80, 82, 83, 89, 90
Reprocessing 32, 65, 87, 88, 97
Reserves 9, 87, 88, 90, 93, 101, 106
- Coal 42, 93, 101, 106
- Crude oil 69, 70, 71, 73-76, 78
- Deferred 61
- Established 55, 56, 58-62, 69-71, 73, 76
- Natural gas 2, 3, 55-62, 107

Residential sector
- *see Sector, Residential*

Resource 2, 9-11, 21, 25, 26, 39, 42, 54, 56, 58, 59, 63, 69, 70, 76, 78, 93, 95, 106, 107
Road 19, 20, 76
Royalties 57, 70, 75, 77

Sable Island 58
Saskatchewan 31, 32, 42, 46, 47, 51, 53, 61, 62, 77, 93, 94, 106
Scotian shelf 28, 60, 89, 90, 106
Sector
- Commercial 13-16, 20, 29, 64, 90
- Industrial 13, 14, 16, 17, 20, 28, 29
- Non-Energy 13, 17-19, 30
- Residential 13-15, 20, 29, 64
- Transportation 13, 14, 19, 20

Self-sufficiency 83, 103
Soft energy 25, 26
Solar 3, 25, 26, 54, 106
Straddle plant 87, 88
Supply capability 60
Synthetic crude oil 69, 76, 87, 89, 106

Taxation 5, 25, 29, 77, 79
Technology 14, 17, 25, 26, 55, 59, 69, 94, 106
Technological changes 9, 10, 58, 75, 78, 106, 107
Thermal Process 75
Thermo-mechanical pulping process 17, 29, 34
Tidal power 43
Transportation sector
- *see Sector, Transportation*

Trucks 19, 20, 80, 93

Ultimate potential 56, 57
Uncommitted gas reserves 61
United States 8, 9, 19, 29, 39, 42, 46-48, 51, 53, 62-64, 76, 77, 85, 94, 95, 101, 103, 107

Upgrading 11, 31, 71, 76-78,
82, 83, 85, 87, 89

Vancouver Island Pipeline 33, 34
Venture 58
Very low permeability reservoirs
55, 58, 59

Waterflooding 71, 74
Wind 54
Wood 16, 25, 26, 28, 29, 31, 33,
34, 63, 64, 102

Yukon 33, 35, 41, 48, 63

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Summary Report

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September 1984

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Foreword

The National Energy Board (NEB) was created by an Act of Parliament in 1959. The Board's regulatory powers under the National Energy Board Act include the licensing of the export of oil, gas and electricity, the issuance of certificates of public convenience and necessity for interprovincial and international pipelines and international power lines, and the setting of just and reasonable tolls for pipelines under federal jurisdiction. The Act also requires that the Board keep under review the outlook for Canadian supply of all major energy commodities, including electricity, oil and natural gas and their by-products, and the demand for Canadian energy in Canada and abroad.

Since its inception the Board has prepared and maintained forecasts of energy supply and requirements and has from time to time published reports on them after obtaining the views of interested parties. The latest of these reports was issued in mid-1981. Since that time the outlook for energy markets has changed, reflecting changing perceptions of the future of energy prices, economic activity, the availability of energy supplies and changes in government policies.

In light of these changes and the concomitant need to reappraise future prospects, the Board, in October 1983, invited provincial governments, industry, major energy consumers and public interest groups, representing a broad cross-section of the energy community to assist in the preparation of an update of its 1981 long term projections of energy supply and demand in Canada. On this occasion, Board staff was requested to prepare a report without the involvement of Board members in a formal hearing process as had previously been the practice. Some 65 written submissions were received and reviewed in early 1984. The Board extends its thanks to those who contributed to the staff's work in preparing these sets of estimates. It hopes that readers will be provided with a useful review of the country's energy prospects.

This Summary Report provides an overview of the major assumptions and results of the analysis of the supply and demand for energy in Canada. The interpretations and conclusions presented are, of course, those of Board staff. More detailed information on forecast assumptions, methodology and results are contained in the Technical Report which can be obtained by contacting the Secretary of the Board at 473 Albert Street, Ottawa, Ontario, K1A 0E5.

Energy Units:

The energy units most commonly referred to in this report are the gigajoule (GJ) and the petajoule (PJ). A 30-litre gasoline fill-up contains about one gigajoule of energy. A petajoule is one million gigajoules. A city the size of Toronto or Montreal uses a petajoule of energy for all uses (heat, light, transportation, etc.) about every 17 hours. The table on the last page of the report shows some key conversion factors we have used in compiling and converting the data used herein.

CONTENTS

Page

HIGHLIGHTS 1

INTRODUCTION 2

ENERGY DEMAND 5

OIL 9

NATURAL GAS 12

ELECTRICITY 15

OTHER ENERGY FORMS 17

TOTAL ENERGY BALANCES 20

HIGHLIGHTS

The main conclusions of the Board staff analysis of the supply of, and demand for, all forms of energy in Canada are:

Demand

The use of energy by Canadian consumers is projected to grow at 1.6 percent a year during the period 1983-2005, about one-third of the annual rate of increase of some 5 percent experienced in the 1960s and 1970s. The lower rate of increase results from more efficient use of energy in all sectors of the economy and from lower economic growth than occurred over much of the past two decades. The market share of oil will continue to decline and the shares of gas, electricity and other energy sources will rise. By 2005, oil will retain only half the market share it had before the first major price increases in 1973.

Oil

Canada currently produces more crude oil than it consumes, when light crude oil and heavy crude oil are considered together. There is a reasonable likelihood that this situation will continue, but this is far from certain because significant production from new oil sands plants and from the frontier areas will be required.

Heavy crude oil and crude bitumen from in situ oil sands projects will be in excess supply throughout the forecast period. We assume that a proportion of heavy crude oil production will be upgraded to augment light oil supplies. Some form of incentive will be necessary, however, to make the upgrading process profitable.

Production from frontier areas, together with new supplies of synthetic oil from oil sands mining plants are critical to our light crude oil forecast. Both supply sources are subject to considerable uncertainty and both are highly dependent for financial viability on oil prices relative to costs, and tax and royalty regimes. Supplies from frontier areas will depend on exploration success in finding large, economically accessible reservoirs.

We are projecting that domestic production of light crude oil will be less than Canadian demand, except for a brief period following initiation of frontier production in 1993. This implies a continuing need for imports.

Gas

Natural gas supply from Western Canada will meet domestic and authorized export demand until about 2005. The date could be a few years earlier, or several years later, depending on the rate of discovery and development of new gas. Thereafter, alternative supply sources, such as the frontier areas or the very low permeability reservoirs in Western Canada, will be required to satisfy Canadian demand.

The cost of finding new Western Canadian supplies will rise over time, as quantities discovered relative to drilling activity continue to decline, and lower productivity reservoirs dominate the production scene. The extent to which it is possible to develop new supply sources to replace conventional production will depend on discovery success, technological progress, and prevailing economic conditions.

Electricity

We see no constraint on the ability of the electrical industry to meet domestic demand during the review period. Canada has large resources of coal, hydroelectric energy and uranium for generating purposes, and generating capacity over and above that required to satisfy the Reference Case demand could be achieved if desired.

At present, the industry in general has adequate reserve generating capacity although the margins vary across the country. In some provinces, considerable excess capacity is available that could support increasing power exports to the United States.

Other Energy Forms

Natural gas liquids will continue to be available to meet Canadian needs, with substantial excess volumes remaining for export.

Coal production will increase to satisfy a growing requirement for electricity generation in Alberta and Saskatchewan, and the export market.

The use of alternative energy forms, including wood, wood wastes and solar power will increase significantly over the projection period but their share of total energy use will remain relatively small, less than eight percent.

INTRODUCTION

In this report, we provide a broad outline of what appear to us to be the major trends in Canadian energy markets, given our analysis of information currently available about the prospects for changes in major underlying variables and the consequent impact on energy supply and demand.

Energy markets in Canada and the world have changed remarkably in recent years in response to a number of factors:

- The oil price shocks of 1973 and 1978-1980 resulted in a dramatic increase in world oil prices; in 1982 the official selling price of OPEC's marker crude was some 17 times greater than in 1972.
- Reflecting the volatility of world oil prices, views about the prospects for future prices have changed substantially in recent years.
- Influenced in significant measure by the oil price shocks, economic growth in Canada and abroad has been markedly lower in the past decade than it had been in the earlier post-war period.
- In Canada, major changes in energy pricing and taxation policies were implemented.

The submissions made to the Board indicate that there remains a considerable range of opinion about the future course of economic activity and world oil prices, and about their impact on energy markets.

There is also uncertainty about future Canadian energy policies. Indeed, some projections we received were predicated on the assumption that there would be changes in energy policies and/or pricing practices. Clearly, policies will change in response to events and in response to the choices of society as reflected in government decisions. It is not the purpose of this analysis to assess the likelihood of policy changes.

It is, nonetheless, necessary to adopt a working hypothesis about the policy framework, and as it is usual, in studies of this kind, to assess the prospects for energy markets in the context of the existing legislation and pricing practices, we conducted our analysis on that basis.

Our approach is to assess independently the prospects for supply of and demand for the major energy forms and then to observe whether the prospects are for a continuation or emergence of an excess supply or demand.

Given all the uncertainties, it would be undesirable and misleading to rely on a single projection of supply of and demand for energy in Canada. It is clearly important to have a Reference Case that, after considering all the evidence, including that from submissions, outlines our assessment of the most plausible profiles of demand and supply. It is also important, however, that we assess a range of outcomes for the supply of and demand for the different energy forms.

The band of plausibility that we have identified for energy supply and demand reflects the uncertainties associated with a wide range of factors. Of critical importance, however, are the prospects for Canadian energy prices and for the level and rate of growth of Canadian economic activity.

Under current policies, Canadian oil and gas prices follow world oil price levels but remain below them to a slight degree in the case of oil, and to a somewhat larger degree in the case of natural gas. The central price assumption in our analysis, therefore, is that relating to the world price of crude oil.

Our projected world oil price reflects the view that the world oil market will be characterized by an excess supply for the next few years but that, as time goes on, world oil demand will increasingly press against productive capacity and oil prices will tend to rise relative to the prices of other goods and services. Our Reference Case projection has world prices remaining relatively steady over the next four years, following which the prices rise at an annual rate of about two percent in excess of the rate of inflation.

The submissions we received contained a wide range of assumptions about world oil prices. We thought it reasonable to adopt the outer bounds of submittors' assumptions as our plausible range of future oil prices. Our assumptions are shown in Figure 1.

From the starting point of world oil prices, Canadian oil prices are projected taking account of the existing framework in agreements between the federal and provincial governments. Natural gas prices are related to oil prices based on existing federal and provincial policies. This means that in Ontario and Quebec, gas prices to distributors are assumed to remain at 65 percent of oil prices. Electricity prices are determined largely by the cost of installing and operating generating capacity, and we have assumed that over the longer run they would rise at a rate equal to the rate of inflation.

The implications of our Reference Case assumption for average Canadian retail energy prices are shown in Figure 2. Relative energy prices at the retail level vary significantly across Canada as a result of such factors as availability and cost of local supply, transmission and distribution costs, and provincial pricing and taxation policies. Generally, however, retail prices in all provinces can be expected to follow similar trends. Under our assumptions, fuel oil and natural gas prices tend to increase relative to the price of electricity over the projection period.

Economic analysts are virtually unanimous in forecasting that the long term trend rate of growth in the Canadian economy will be slower in the future than it has been in the past 20 years. This is largely because it is virtually certain that the rate of growth in the Canadian population and workforce will be slower in the future than it has been in the past two decades, and the rate of productivity growth, though accelerating somewhat from its recent very low levels, will remain somewhat below the trend rate of growth which has occurred in the past.

At present, the Canadian economy is operating significantly below capacity, so that over the next few years, it has the ability to grow at a rate significantly in excess of its potential growth rate over the longer term. For a number of reasons, the prospects for economic growth in Canada and, indeed, in the industrial world, are extremely uncertain and we thought it prudent to adopt the assumption, for the Reference Case, that economic growth would be moderate in Canada over the next few years. Our economic growth assumptions are illustrated in Figure 3. Under our Reference Case, the Canadian economy grows at an annual rate averaging 3.4 percent in the years to 1990, a rate of growth that would still leave the economy operating somewhat short of its productive capacity by the end of the decade. For the 1990s and beyond, we assume a rate of growth in real GNP in Canada of about 3 percent a year.

Recognizing the possibility of a medium term growth path weaker than that of the Reference Case, we have assessed the implications for energy demand if economic growth in Canada were to average some 2 percent a year over the remainder of the 1980s, and a somewhat higher rate in later years. We have also assessed the implications for energy demand if economic growth

Figure 1
World Oil Prices

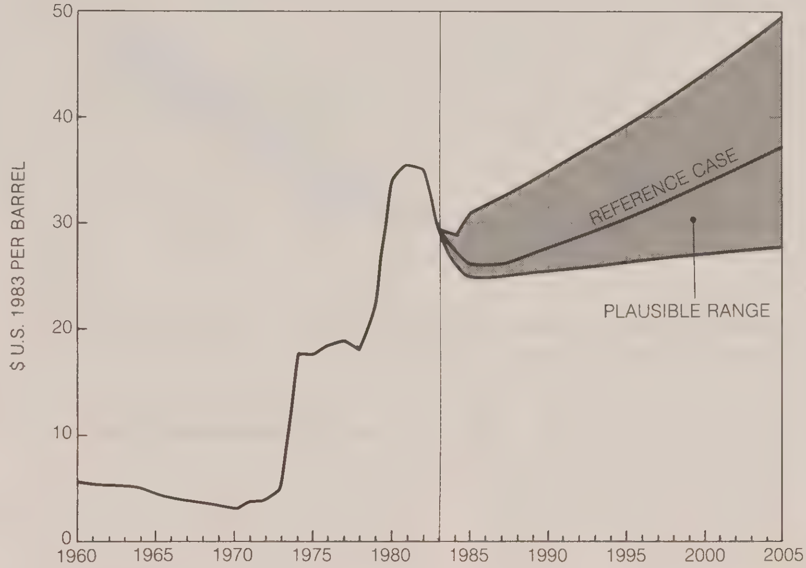
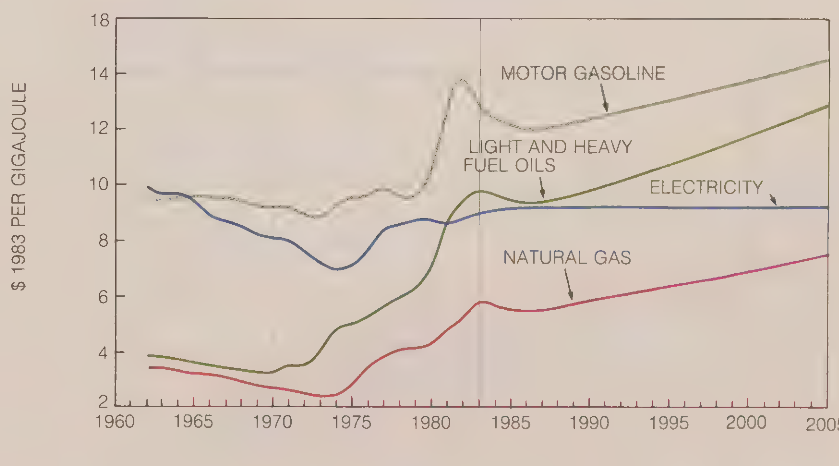
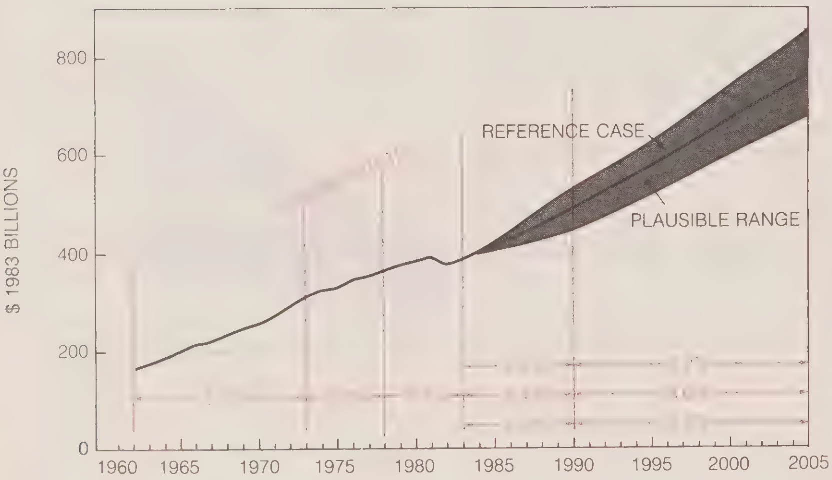


Figure 2
Average Retail Energy Prices[1], Canada



[1] Fuel oils and natural gas prices have been adjusted for burner tip efficiencies

Figure 3
Canadian GNP Growth
Annual Growth Rates in Percent



were to proceed at a significantly faster pace in the 1980s so as to approach productive capacity by 1990. Our high growth scenario has economic activity rising at rates averaging some 4.5 percent per year through 1990 and 3.2 percent per year thereafter.

We outline below our projections of energy demand. This is followed by a summary of the supply and demand outlook for each energy form and then by a discussion of total energy balances.

ENERGY DEMAND

Between 1980 and 1982, end use energy demand in Canada declined by eight percent; in 1982, end use requirements were only marginally above their 1977 level. Growth in energy demand has resumed in recent months, and given our assumptions about economic activity, it can be expected to continue to grow. The impact of economic growth will, however, be mitigated for some years to come as we continue to respond to the very large energy price increases of recent years.

For the rest of the 1980s, we expect energy demand to grow at an average annual rate of only about one percent. Over the longer period to 2005, energy demand growth is projected to average some 1.7 percent a year reflecting our assumption of growing economic activity in an environment of relatively stable energy prices. Our projection of energy use by sector is shown in Figure 4.

Energy use is likely to grow particularly slowly in the residential sector, at a rate of about only 0.5 percent a year. The number of households will be increasing at much lower rates than have occurred in the past. The energy efficiency of households is likely to improve significantly over time as the proportion of new, more energy efficient, residences in the housing stock increases and as greater use is made of more energy efficient space heating and other appliances.

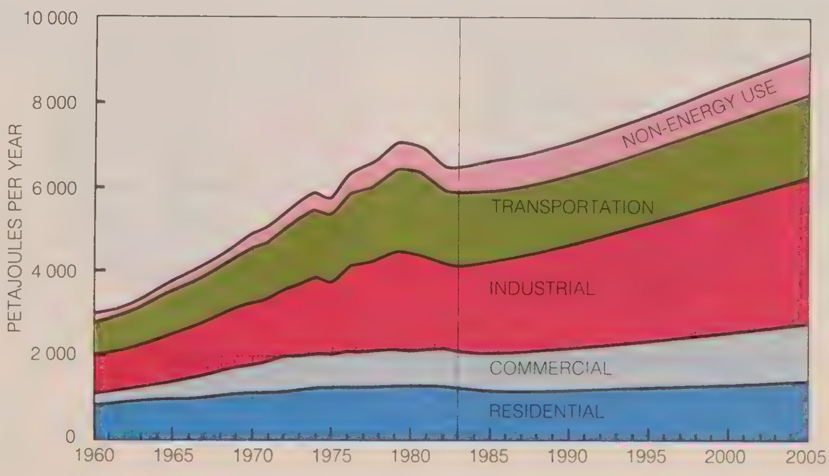
For the commercial sector of the economy, which constitutes all service industries in the economy except transportation, we are projecting growth in energy use of about 2 percent a year between 1983 and 1990. This reflects the net effect of a more rapid rate of growth in economic activity than has recently occurred, offset to some extent by improvements in the efficiency of energy use. Over the longer run, energy demand in this sector, dominated by growth in economic activity, is projected to grow somewhat more quickly at a rate of 2.5 percent a year.

The goods producing industries are, in total, the largest consumers of end use energy in Canada. The use of energy is highly concentrated in the mining, iron and steel, pulp and paper, and industrial chemicals industries, which collectively use some two-thirds of the energy consumed in industry. In the past, energy use in industry has grown at about the same rate as industrial output. Our assessment is that there is considerable potential for conservation in industry, and that, as investment spending grows in the future, industry will be putting machinery and equipment in place that is much more energy efficient than that which it replaces.

Thus, we project end use energy demand in industry to grow at a significantly lower rate than industrial output. Because the goods producing industries were most affected by the 1982 recession, the recovery in their output is likely to be relatively rapid in the next few years. Moreover, unlike some analysts, we assume that the goods producing industries will maintain their share of GNP near 1981 levels. As a consequence, energy demand in this sector grows throughout the projection horizon at an average annual rate of about 2.5 percent. Notwithstanding this relatively rapid rate of increase in industrial sector demand for energy, the level of energy use does not regain its 1980 level until 1988.

Next to the industrial sector, transportation is the largest consumer of energy, which in this case consists virtually entirely of oil-based products. Some 80 percent of the energy used in transportation is consumed by road vehicles. Energy used in transportation grew at a rate of about 6 percent a year in the 1960s and early 1970s, slowed to 3 percent between 1973 and 1978, and since then, has actually declined.

Figure 4
End Use Energy Demand, Canada



We are projecting a further marginal decline in energy used in road transportation through 1990, with very modest growth occurring thereafter. Underlying this projection is the assumption that energy demand for use in automobiles will continue to decline but the impact of this decline will be moderated by an increase in fuel used by trucks.

In our Reference Case, energy demand for use in automobiles is projected to decline in spite of a considerable increase in the rate of new car sales from recent levels. This decline is based on the assumption that the proportion of smaller cars will continue to rise, and that fuel efficiencies will continue to improve significantly for the next few years. The average fuel efficiency of cars is projected to increase from its current level of 14 litres per 100 kilometres, to 8 litres per 100 kilometres in 2005 (from 20 to 36 miles a gallon). Fuel use by trucks is projected to grow more strongly than for automobiles. We have assumed only modest improvements in the fuel efficiency of the truck fleet and we are projecting relatively strong growth in the stock of trucks to accommodate a growing need for freight transportation.

In our view, the energy used in road transportation is likely to continue to consist overwhelmingly of gasoline and diesel fuel. Because the proportion of trucks using diesel fuel will continue to increase, the share of diesel fuel is projected to increase from about 16 percent in 1983 to some 26 percent by 2005. It seems probable that there will be increasing use of propane and natural gas for vehicles, and that use of these new fuels will occur mainly in commercial vehicles. The share of propane and natural gas in road sector energy demand is projected to rise to about 5 percent by 2005, representing some 600 000 vehicles. This is a considerable increase over the current share of 0.3 percent of energy demand for 25 000 vehicles.

Use of oil and gas for petrochemical and other non-energy production is likely to grow modestly. Some 590 petajoules of hydrocarbons were used for these purposes in 1983 (52 percent oil, 39 percent gas and 9 percent natural gas liquids). Almost two-thirds of this use was for petrochemical production and, of the remaining 200 petajoules, over one-half was used in the production of asphalt.

Demand for petrochemical products has begun to recover and growth can be expected to continue with growth in the industrial economies. All of the growth in demand for petrochemical feedstocks will occur in natural gas and natural gas liquids. The use of oil is likely to decline both in absolute and relative terms.

Market Shares

Since the early 1960s, energy use in the residential, commercial and industrial sectors has shifted substantially from oil. Residential and commercial users have been switching to natural gas and electricity, the pulp and

Figure 5
End Use Energy Market Shares, Canada

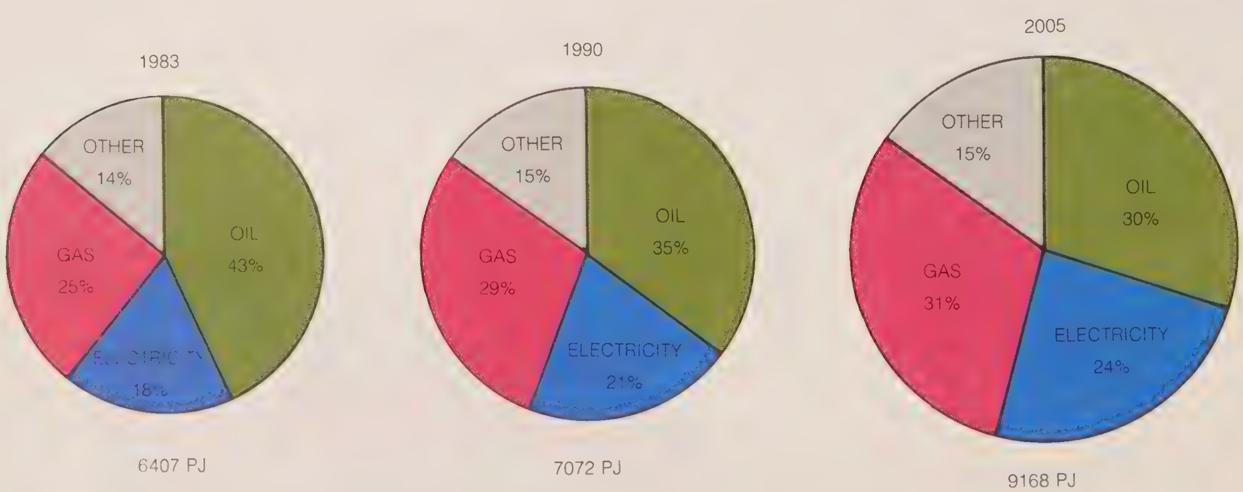
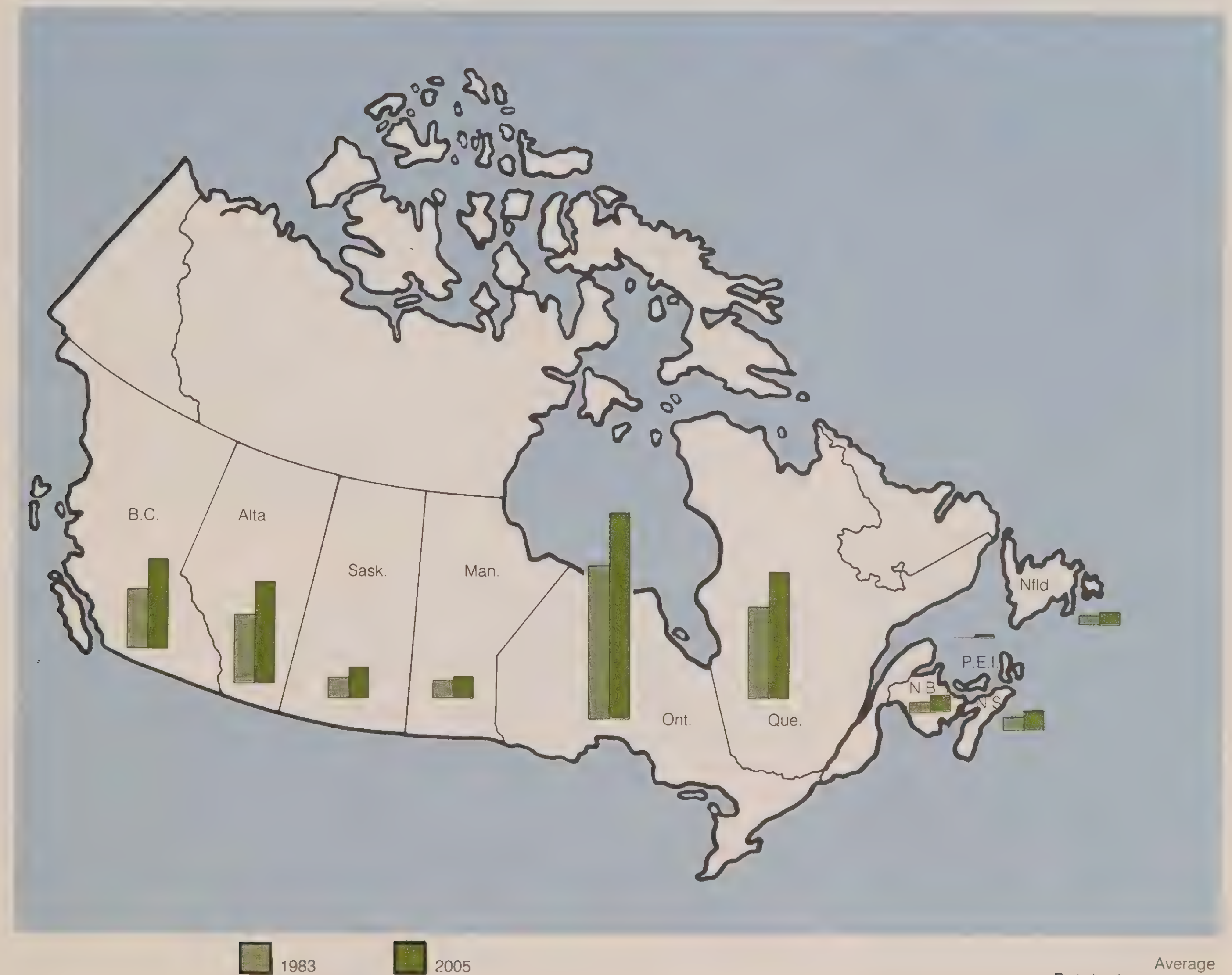


Figure 6
Regional Energy Use

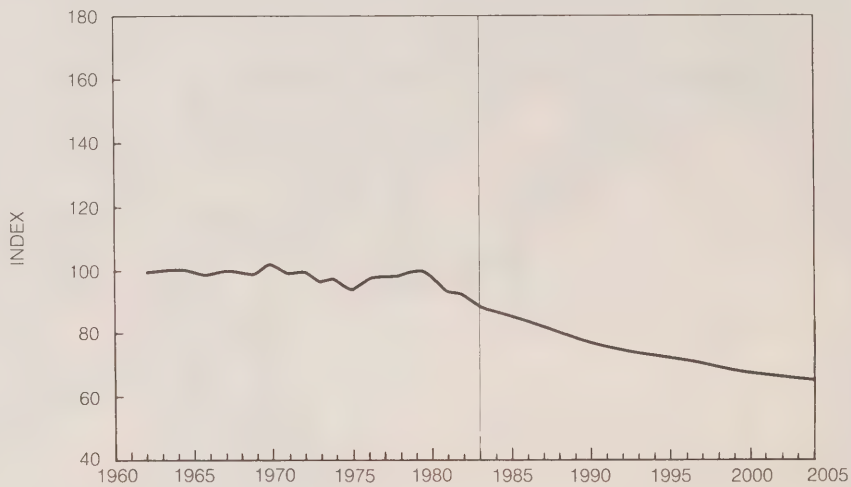


	Petajoules 1983	Petajoules 2005	Average Annual Growth (%)
Canada	6407	9168	1.6
Quebec	1340	1850	1.5
Ontario	2260	3092	1.4
Manitoba	226	297	1.2
Saskatchewan	281	414	1.8
Alberta	976	1546	2.1
B.C. & Terr.	859	1302	1.9
Newfoundland	117	163	1.5
P.E.I.	17	21	1.0
Nova Scotia	179	257	1.7
New Brunswick	151	226	1.8

paper industry to waste wood and pulping liquor, and other industries to natural gas.

More recently, the shift from oil has been encouraged by the high relative price of oil and by various government programs and policies, including the Canadian Oil Substitution Program, financial support for the extension of the natural gas transmission system, the Industrial Conversion Assistance Program (for natural gas), and the Forest Industry Renewable Energy Program.

Figure 7
End Use Energy Demand Per Unit of Real GNP
1962 = 100



Abundant supplies in Canada of both natural gas and electricity have led to intense competition between these two fuels, particularly in Quebec. In addition to the various government initiated off oil programs, both electric utilities and natural gas distributors have introduced incentives to induce consumers to convert from oil. The outcome of this competition is uncertain, but, whatever happens, it is virtually certain that the declining trend in the share of oil will continue. We project oil use in residential, commercial and industrial sectors taken together to be only 71 percent of its current level by 1990.

The distribution of total energy demand in Canada reflects the regional distribution of the population. Eighty-five percent of Canada's energy use is concentrated in the four largest provinces, British Columbia, Alberta, Ontario and Quebec. It also reflects the differences in the composition of economic activity in different parts of the country. Alberta, for example, uses proportionately more energy per capita and per unit of total output than does Ontario; its economy is to a large extent based on the energy industries which, themselves, are highly energy intensive.

In the period from 1960-1980, there was a relatively constant ratio of end use energy demand to real GNP in Canada, as shown in Figure 7. If such a relationship were to continue in the future, the rate of increase in energy use would be equal to the rate of increase in GNP. Since 1979, however, energy use has been growing at a slower rate than has GNP. Our assessment of the prospects for energy use in the different sectors of the economy suggests that this trend will continue, so that by 2005 there could be an improvement of up to 27 percent in the efficiency with which energy is used in the Canadian economy.

OIL

The demand for crude oil in Canada fell from its 1979 peak of nearly 300 000 cubic metres a day to about 230 000 cubic metres a day in 1983. Our projection shows a continued but slower decline in oil demand through the 1980s, to about 200 000 cubic metres a day in 1990, in response to more efficient use of oil and the substitution of other fuels in residential, commercial and industrial markets. Oil use in the transportation sector and for non-energy uses, such as the manufacture of asphalt and petrochemicals, generates a small increase in total oil demand in the 1990-2005 period, so that demand returns to about the 1983 level by 2005.

Underlying our Reference Case projection are the assumptions that there will be considerable improvement in vehicle fuel efficiencies, that the mix of cars will shift significantly in favour of small cars, and that there will be a substantial further decline in the use of oil in residential, industrial and commercial uses. There is, of course, considerable uncertainty about each of these and oil demand could, we estimate, be some 13 percent greater or lower than our Reference Case by the year 2000. There is, in our view, a greater risk that our Reference Case has understated, rather than overstated, oil demand.

On the supply side, Canada is now dependent on conventional oil from the Western Canada Sedimentary Basin. This basin is in a mature stage of development. The rate of finding and developing conventional crude oil reserves is averaging only about half the rate of production. More conventional oil has already been produced from this area than is expected to be available in total, from remaining established reserves, future enhanced oil recovery, and future discoveries. Figure 9 shows the relative magnitudes of these supply components. Although the amount of oil that can be produced from established reserves using conventional techniques is not in doubt, the high costs of additional extraction using enhanced recovery techniques and the increasing difficulty of finding smaller accumulations of new oil in areas that are generally well explored make these supply sources relatively uncertain.

In light of the diminishing ability of conventional oil resources to meet domestic needs considerable emphasis in the future will be placed on development of the frontier areas and the oil sands. Our Reference Case projection of oil supply contemplates that the proportion of production from the various sources will change over time, as set out in Table 1.

By 2005 the proportion of synthetic crude oil and oil from the frontiers is projected to constitute 68 percent of total light crude oil supply. However, development of both these sources is fraught with uncertainty. In the case of the oil sands the resource is vast and known, but the costs of production are high. The extent of development will depend on oil prices, future costs, fiscal terms and the financing capability of the industry. In the case of supply from frontier areas, there appears to be considerable potential for new discoveries. Considerable effort has been spent on frontier exploration in recent years and some success has been achieved in the Hibernia and Beaufort Sea areas. Though economic factors are important, the major uncertainty about the frontier regions has to do with whether economically accessible oil reservoirs will be found.

Because of the very different qualities and markets for light and heavy crude oil, separate balances of supply and requirements have been prepared.

Figure 8
Oil Demand, Canada

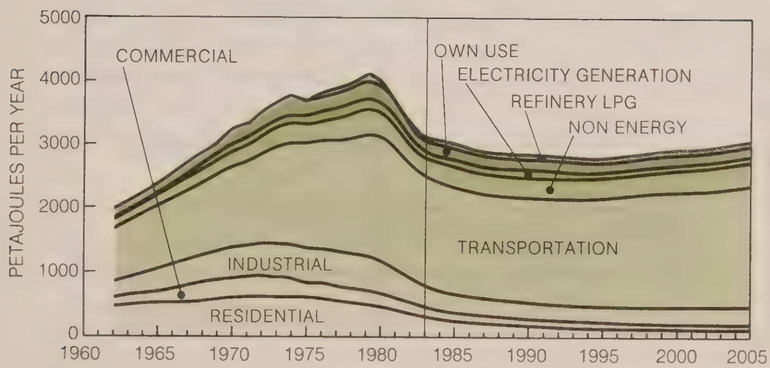


Figure 9
Crude Oil Reserves (Excluding oil sands and frontier)

(millions of cubic metres)

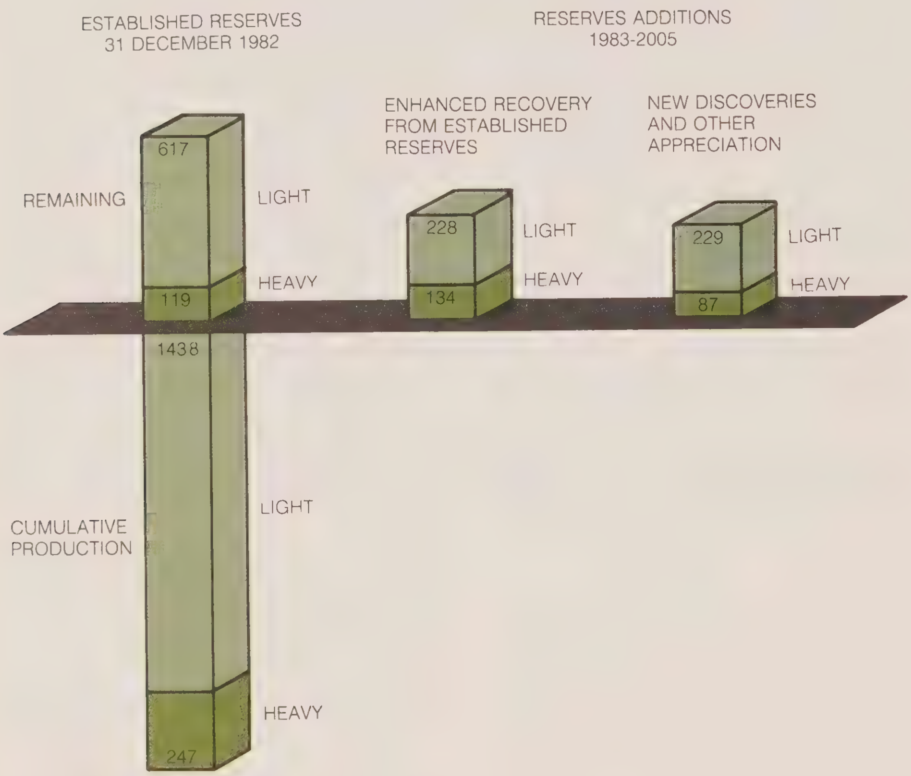


Table 1
Sources of Crude Oil Production
Thousands of Cubic Metres a Day

	1983	1990	2005
Conventional Light and Pentanes Plus	174.1	117.5	49.9
Oil Sands Synthetic (including Upgrading Heavy)	23.5	42.5	63.5
Frontier	—	1.9	44.0
Total Light	197.6	161.9	157.4
Blended Heavy Crude and Bitumen	43.9	39.1	59.2
Total	**241.5**	**201.0**	**216.6**

Figure 10 shows the projected Reference Case supply and demand balance for light crude oil. At present, we have enough light crude oil supply to meet all of Canada's needs, although some is being exported from Western Canada and approximately equal volumes are being imported into the Atlantic and Quebec regions. The supply is projected to decline during the rest of the 1980s, but to increase in the early 1990s as frontier oil is brought to market. This figure clearly shows the critical importance of frontier and synthetic sources to the future supply of light crude oil. If these supplies fail to materialize then Canada's dependence on imports of foreign crude oil could be substantially greater than indicated in our Reference Case.

The supply/demand balance for heavy crude oil is shown in Figure 11. Unlike the situation for light crude oil, we project a persistent excess of heavy crude oil supply over demand. Even after provision is made for the upgrading of heavy crude oil, an excess supply of about 25 000 to 35 000 cubic metres a day persists. This excess supply is now being exported to the United States, mainly to refineries on the Interprovincial-Lakehead pipeline system. Part of the heavy crude oil stream consists of pentanes plus, a light oil produced from the processing of natural gas, that is added to reduce the viscosity of the heavy crude so that it can be transported by pipeline. The prospective availability of adequate volumes of pentanes plus is of some concern, although construction of heavy crude oil upgraders will help alleviate this problem.

The plausible ranges of supply and requirements for light and heavy crude oil combined are shown in Figure 12. There is a reasonable likelihood that Canada can remain self-sufficient in oil but, as is evident from the figure, this is far from certain. As indicated by the ranges, there is more uncertainty about

Figure 10
Supply and Demand Balance for Domestic Light Crude Oil
Canada

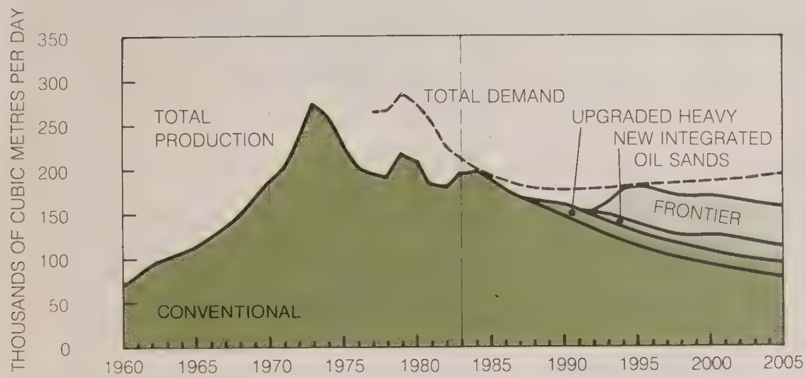


Figure 11
Supply and Demand Balance for Domestic Heavy Crude Oil
Canada

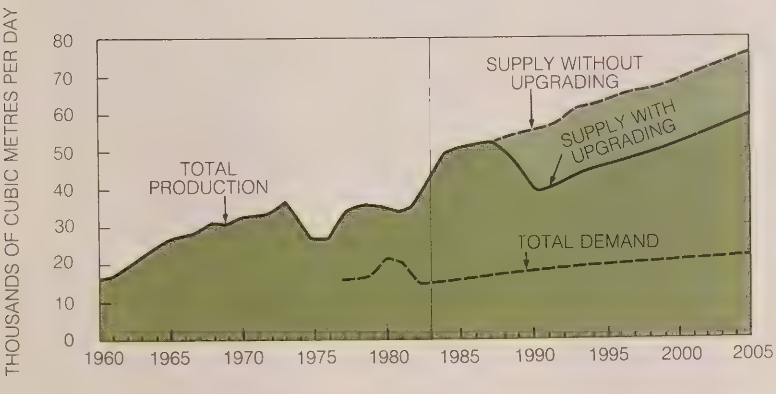
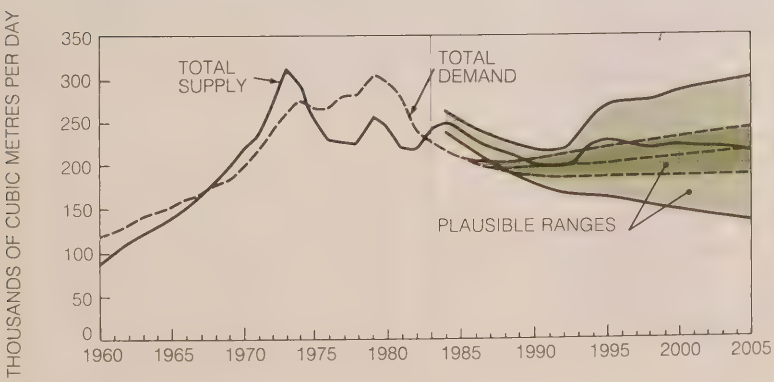


Figure 12
Plausible Ranges for Crude Oil Supply & Demand



future domestic supply than about demand.

Even in the event that there is sufficient domestic oil production in total to meet all domestic requirements, it is likely that exports of heavy crude oil to the United States and imports of light crude oil to Eastern Canada will continue. Exports and imports of petroleum products are also expected to continue, but these are small compared to total requirements.

NATURAL GAS

Since the early 1970s, Canada's total domestic and export sales of natural gas have remained almost constant at about 2800 petajoules a year, while annual additions to reserves have averaged close to 5000 petajoules. The result has been annual deliverability exceeding domestic and export demand by as much as 2000 petajoules in 1983 and 1984. Although much of this excess deliverability is licensed for export, increased supply and declining demand in the United States, and the higher cost of Canadian supply, have resulted in decreased market opportunities for Canadian gas. As a consequence, exports have not attained authorized levels. In domestic markets, although gas is the least costly fuel in Ontario and Western Canada, growth in demand has recently been slow because of low economic activity and increasingly efficient use of energy.

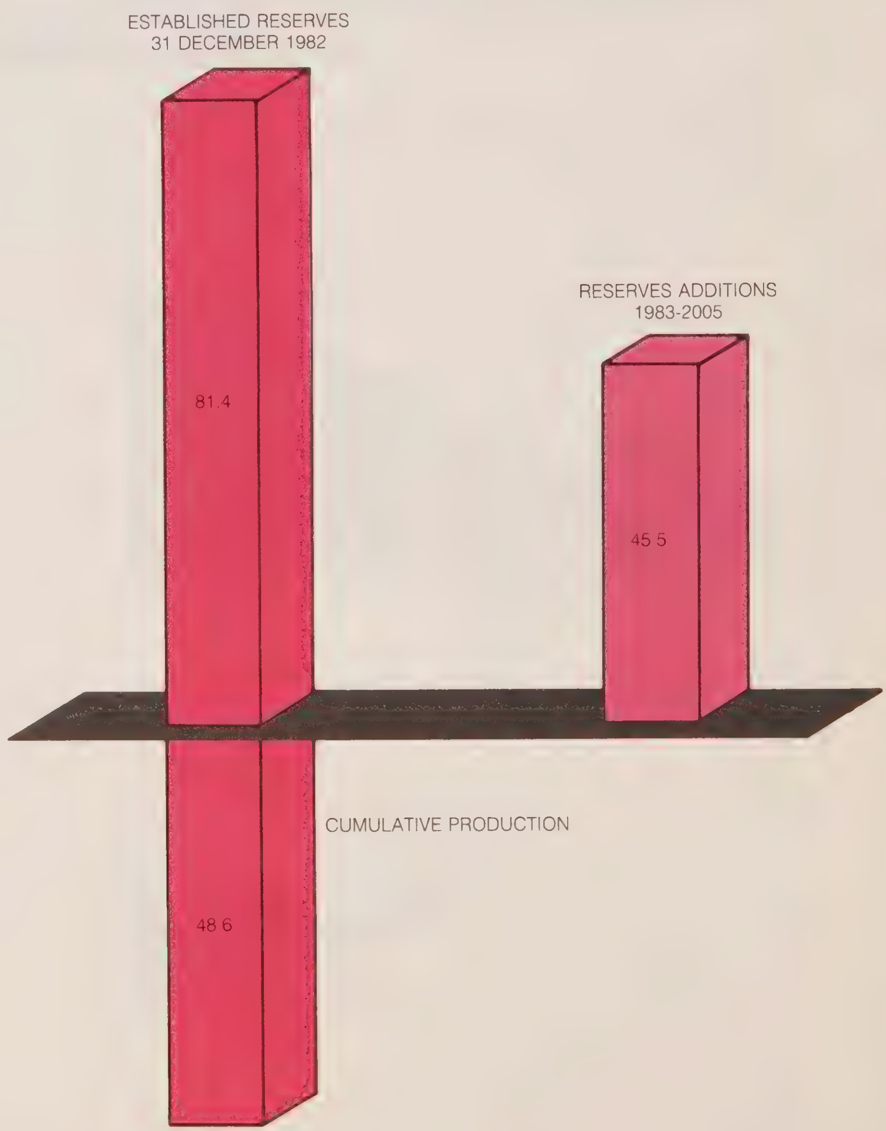
End use demand for natural gas in Canada is expected to increase considerably from 1600 petajoules in 1983 to 2900 petajoules by 2005. Markets are likely to expand as gas is introduced into areas that have not previously been served, and as oil continues to be displaced. Distribution systems in Quebec, east of Montreal, have recently been completed, and the process of connecting new customers is underway. We project that the use of gas in Quebec will increase from 134 petajoules in 1983 to 312 petajoules by 2005. Use of gas should also be practical in Nova Scotia and New Brunswick by 1990 as Scotian Shelf reserves are connected; demand in those provinces is expected to reach a total of 79 petajoules by 2005.

In Ontario and Western Canada, gas is now the predominant fuel in all uses other than transportation. Influenced by the price advantage of natural gas, its share is expected to increase from 42 percent in 1983 to about 45 percent by 2005.

The supply of natural gas through the forecast period will be dominated by conventional gas from Western Canada. Established reserves at the end of 1982 are estimated at 81.4 exajoules – about 30 times current annual production of 2.8 exajoules. This contrasts with conventional oil, where the reserves are only 10 times current annual production

Figure 13
Natural Gas Reserves (Excluding Frontier)

(Exajoules)



levels. We are projecting natural gas reserves additions to 2005 of 45.5 exajoules. It is becoming more expensive to find and develop gas in Western Canada. Increasingly, gas will be produced from poorer quality reservoirs; production per well will be much lower than has been experienced historically.

Eighty-nine percent of Canadian gas production now comes from Alberta and 9 percent from British Columbia. It is projected that by 2005 Alberta and British Columbia will still supply most of the nation's requirements. By that time the East Coast offshore and Arctic regions could supply some 15 percent of the total.

Demand levels by 2005 could be some 11 percent above or 8 percent below the reference projection. Deliverability from Western Canada by the same year could be as much as 20 percent higher or lower than in our Reference Case, depending on the pace of reserves development. The excess of supply over demand could disappear as early as the turn of the century, or persist for many years beyond.

Since 1982 natural gas exports have averaged only 40 percent of authorized levels. It is anticipated that annual exports will return to about 90 percent of authorized volumes by 1990, as demand in the United States recovers and its excess indigenous supply is used up. Should this occur, exports would rise to a level of some 1850 petajoules a year by then, from current annual levels of some 800 petajoules.

Figure 14
Total Natural Gas Demand

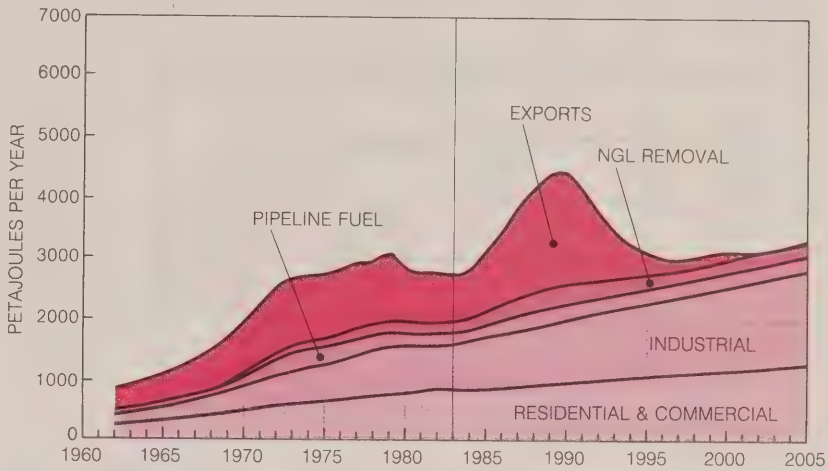


Figure 15
Canadian Gas Supply

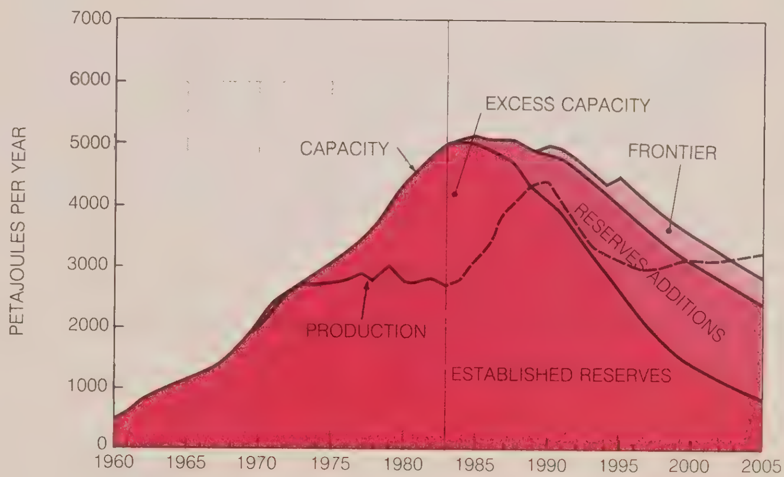
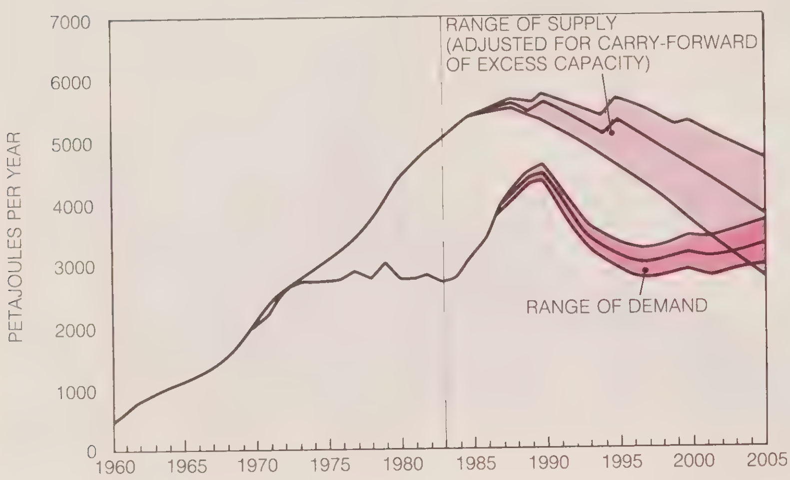


Figure 16
Plausible Ranges of Gas Supply and Demand



ELECTRICITY

The responsibility for ensuring adequate supplies of electricity in each province rests with the provincial governments and the electric utilities. A federal crown corporation supplies most of the electricity in the territories. Energy sources for electricity production differ by region. In Alberta, Nova Scotia and Saskatchewan, for example, expansion plans are based largely on the development of local coal deposits, while in British Columbia, Manitoba and Quebec, hydro developments predominate. In Ontario and New Brunswick, nuclear power forms the cornerstone of current expansion plans.

In general, electric utilities currently have excess generating capacity as a result of expansion commitments made in the 1970s to meet levels of demand that have not materialized. Because of this excess capacity, electric utilities are aggressively marketing electricity in domestic and export markets.

Demand for electricity is expected to grow at about three percent a year over the projection period, significantly faster than growth in total end use energy demand.

Given this demand growth and committed increases in generating capacity, it is expected that excess generating capacity will persist into the 1990s. As a consequence, utilities are hoping to arrange for exports of firm power in addition to sales of interruptible energy which have formed about 80 percent of exports.

Over the longer run, our projections imply that generating capacity in Canada will have to increase from 84 gigawatts in 1983 to almost 150 gigawatts in 2005. The projected generating capacity by fuel type for selected years is shown in Table 2.

Table 2
Generating Capacity by Fuel Type – Canada

	1983		1990		2005	
	Gigawatts	Percent	Gigawatts	Percent	Gigawatts	Percent
Coal	16.4	19	18.4	18	26.0	18
Hydro	50.1	60	58.9	59	86.4	59
Nuclear	7.6	9	13.5	13	22.7	15
Oil & Gas	10.4	12	9.6	10	12.0	8
Total	84.5	100	100.4	100	147.1	100

Throughout Canada, hydroelectric generating capacity is expected to remain at about 60 percent of total generating capacity through to 2005. Nuclear generating capacity increases substantially in importance. Coal-fired generating capacity will increase in absolute terms but its relative share will decrease slightly. The share of oil and gas-fired generating capacity decreases by a third from 1983 to 2005.

While there will be some increase in generating capacity using non-conventional processes such as tidal and wind power, these methods are unlikely to account for an appreciable portion of total generating capacity during the period under review.

There are several different types of generating units, each designed for a particular type of service corresponding to the amount of time the unit may be required to operate. For instance, a base load nuclear unit may operate for 85 percent of the time, producing considerable energy, while an oil-fired peaking unit of the same capacity may operate only 5 percent of the time, producing little energy. Because of this, projections of the distribution of electricity production by fuel type are different from projections of the distribution of generating capacity by fuel type. Table 3 shows how the distribution of electricity production by fuel type may change over time.

On a Canada wide basis, the share of hydro in total energy production is projected to continue to decline. We also project a decline in the share of fossil

Table 3
Electricity Production by Fuel Type – Canada

	1983		1990		2005	
	Terawatt hours	Percent	Terawatt hours	Percent	Terawatt hours	Percent
Coal	68.5	17	75.9	15	99.9	14
Hydro	267.9	68	311.7	62	434.0	62
Nuclear	44.2	11	94.5	19	151.9	22
Oil & Gas	15.4	4	18.2	4	13.5	2
Total	396.0	100	500.3	100	699.3	100

fuels (coal, oil and natural gas). In contrast, the share of nuclear is projected to double over the projection period.

As with installed capacity, the types of fuels used to produce electricity vary from one region to another with each utility choosing to make the best use of the resources available to it. Significant transfers of electricity occur between provinces but the magnitude of such movements is limited by economic factors; electrical transmission is a relatively expensive way to move energy over the long distances separating many of the population centres in Canada. It is frequently found that the United States provides more economically accessible markets for power available in excess of Canadian utilities' requirements. Annual exports for the forecast period are projected to range from 3 to 13 percent of total Canadian electricity production.

Figure 17
Electrical Energy Demand

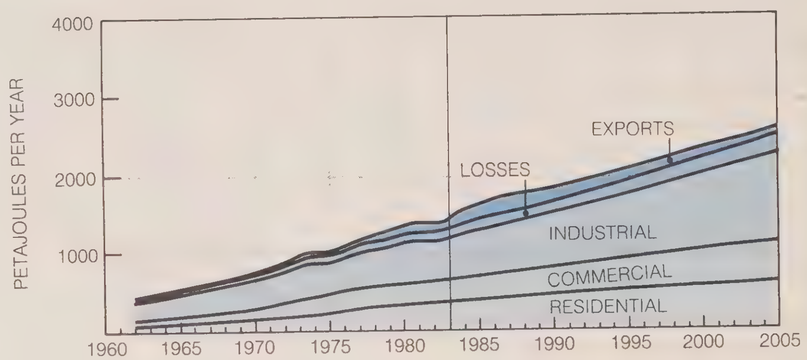
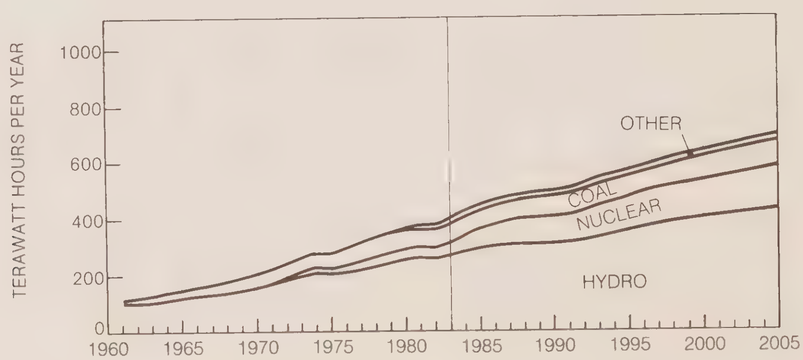


Figure 18
Electricity Production by Fuel Type, Canada



OTHER ENERGY FORMS

Natural Gas Liquids

Natural gas liquids consist of ethane, propane, butanes and pentanes plus. These materials are extracted from natural gas streams and are also produced in the refining of crude oil. About three-quarters of the production comes from gas plants.

Each natural gas liquid is used differently because of its unique characteristics. Ethane is used in Canada mainly as a petrochemical feedstock to manufacture ethylene and as a fluid injected into oil reservoirs to increase crude oil recovery. Propane has a variety of end uses including cooking, space heating, crop drying, tobacco curing and as motor fuel. Like ethane, propane is also used as a petrochemical feedstock and to increase oil recovery. Butanes are used mainly in gasoline manufacturing, either in the chemical processes or as a blending component, and as a petrochemical feedstock. Pentanes plus is suitable for use as a refinery feedstock and we include it as part of light crude oil supply.

Canadian production of ethane, propane and butanes is about double domestic requirements. Volumes in excess of Canadian needs are for the most part exported to the United States. Table 4 summarizes our projection of production and demand for natural gas liquids.

Coal

During the 1950s, oil and gas replaced coal as the largest energy source in Canada. As oil prices have increased, however, coal has become more attractive in a variety of industrial uses. At present, coal from Western Canada, in addition to supplying local needs, is exported in large quantities, and recently has become a significant component of Ontario supply. Coal demand, reasonably constant through the 1960s and early 1970s, has since risen significantly and is expected to further increase in the future, mainly as a result of increasing requirements for electricity generation.

Canada possesses vast resources of bituminous and subbituminous coal and lignite. Total recoverable reserves are estimated at 6300 megatonnes which, at the 1982 annual production rate of 43 megatonnes, would support production for nearly 150 years. Canadian coal deposits occur under a variety of geological conditions that determine the most appropriate mining technique. In 1982, 91 percent of Canadian coal was produced by surface mining in Western Canada, the remainder from underground mines in British Columbia, Alberta and Nova Scotia. Bituminous coals accounted for 52 percent of 1982 production, and subbituminous coals and lignite for 30 and 18 percent, respectively.

Development of coal depends not only on the occurrence of the resource itself but also on such factors as transportation, market development and environmental considerations. Efficient rail service and bulk loading facilities on the West Coast were developed to take advantage of the opportunity for export sales. To supply Ontario markets, Western coal is carried by rail to Thunder Bay and delivered from there by ship.

About 75 percent of coal used in Canada is for the generation of electricity, mainly in Alberta and Ontario. Coal is also consumed by industry primarily in the manufacture of iron and steel, and cement. Demand is projected to increase at an annual rate of 2 percent to about 65 megatonnes (1560 petajoules) by 2005.

Canada has three distinct coal markets: the Atlantic region produces and uses its own coal and exports some; Ontario imports most of its coal from the United States; and the West produces and uses its own coal,ships some to Ontario, and exports large quantities through British Columbia ports.

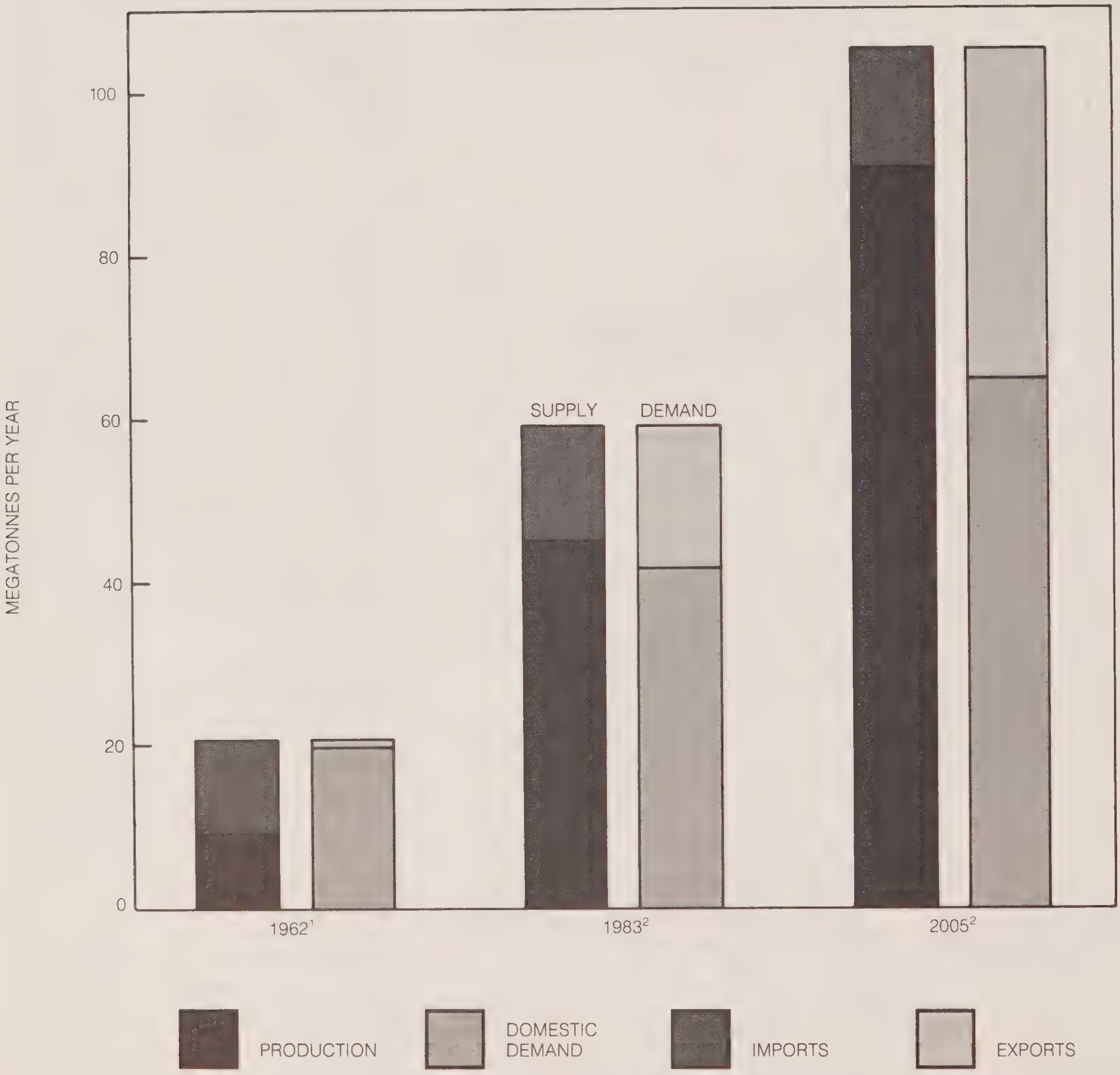
At present, Canadian coal production is slightly in excess of domestic demand. Although exports are in excess of imports, Canada is still a net importer of thermal coal. Canadian production has increased dramatically in recent years and this trend is expected to continue. Figure 19 shows the relative magnitudes of past, present and future coal supply and requirements.

Table 4
Natural Gas Liquids Production and Demand

Thousands of Cubic Metres a Day

		1983	1990	2005
Ethane	Production	13.5	27.9	17.6
	Demand	5.9	23.7	17.2
Propane	Production	18.7	25.5	18.6
	Demand	10.5	19.2	14.3
Butanes	Production	12.1	15.6	11.2
	Demand	5.2	9.5	7.2

Figure 19
Coal Supply and Demand, Canada



Alternative Energy Forms

In addition to the energy forms discussed above, alternative sources including wood, wood waste and pulping liquor make a significant contribution to energy use in Canada. It is estimated that these sources currently account for over seven percent of our total energy requirements. This share is expected to be maintained as total energy demand grows throughout the forecast period. Minor contributions are expected in the later years of the projection period from municipal solid waste, active solar energy and peat.

In British Columbia, wood wastes make up about 23 percent of total energy requirements, mainly as a result of use by the forest industry itself. In Atlantic Canada as well as in other areas of the country, wood is also becoming more attractive as a source of heat in households. In the Atlantic provinces, for example, wood is now estimated to constitute 25 percent of the residential heating market. Use of wood in this manner is, of course, much more prevalent in rural areas and in the more forested provinces. We are forecasting that wood will provide about 8 percent of Canada's residential heating needs by 2005 compared to 4 percent for oil.

In order for alternative energy forms other than wood, such as solar or biomass, to make a more substantial contribution than we are projecting, either energy prices would have to increase much more rapidly than now seems likely, or significant technological breakthroughs would be required.

TOTAL ENERGY BALANCES

Before the 1960s, Canada was a net importer of energy. Since that time, with the development of oil and gas in Western Canada, energy production has exceeded domestic needs and we have become significant net exporters of energy. In 1983, net energy exports represented about ten percent of total production and had a value of $7.8 billion. Canada was a large exporter of oil, natural gas, electricity, coal and natural gas liquids, and imported smaller amounts of oil and coal.

Our projections of the composition and levels of total energy demand and production are shown in Figures 20 and 21. Electricity does not appear on these figures because they show only primary energy forms. The hydro and nuclear components, about three-quarters of the coal, and minor amounts of oil and gas constitute the energy used to manufacture electricity. Our analysis suggests that, when all primary energy forms are combined, Canada will continue to be a large exporter of energy.

- The share of oil in both demand and supply of total energy is projected to fall from current levels. Provided frontier and oil sands production is achieved as projected in our Reference Case, the market for domestic crude in Canada is likely to be close to being in balance.
- Natural gas demand increases relative to that for other fuels. The contribution of natural gas to total energy production increases particularly rapidly in the 1985-1990 period, as exports approach authorized levels.
- Natural gas liquids are a small portion of total energy supply and requirements; production is now in excess of domestic requirements and this situation is likely to continue.
- The proportion of coal in energy demand remains relatively constant throughout the projection period. As noted, Canada has recently become a net exporter. Because deposits are large relative to foreseeable needs, coal may well provide the greatest potential for long term exports of Canadian energy.
- The primary energy forms used to generate electricity, mainly hydro, nuclear and coal, will constitute a growing share of total supply and demand. Electricity supply is governed by domestic demand. Exports, for the most part, are made up of interruptible off-peak power.

Figure 20
Total Canadian Energy Demand

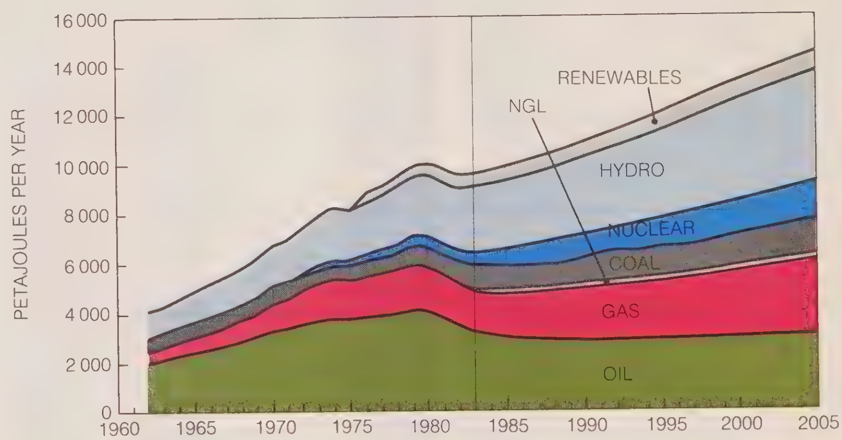
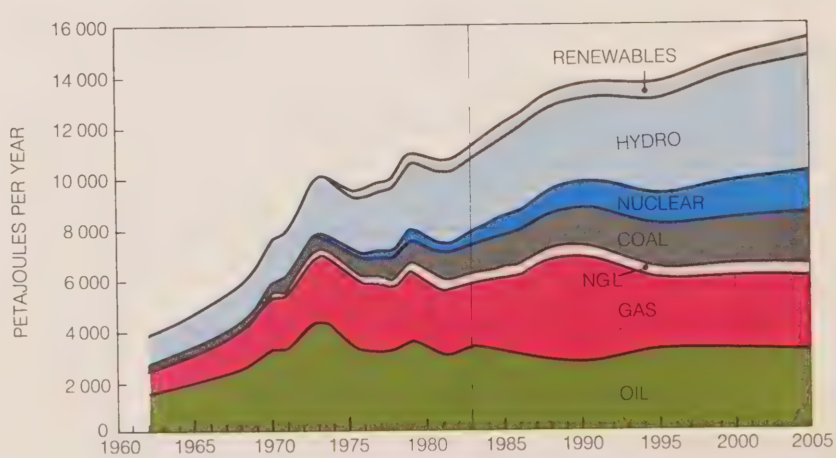


Figure 21
Total Energy Production



Increasingly, however, utilities are considering exports of firm power from generation constructed or advanced for that purpose.

Compared to other industrialized countries, Canada is well endowed with energy resources. Among the 24 OECD member nations, only Norway, Great Britain, Australia, the Netherlands and Canada are net exporters. Our projections imply that energy production in total will remain significantly in excess of demand through 2005.

Approximate Conversion Factors

1 cubic metre	contains	6.3 barrels, 35.3 cubic feet
1 petajoule	"	950 billion British thermal units (Btu)
1 cubic metre of natural gas	"	38 megajoules of energy
1 petajoule of natural gas	"	0.95 billion cubic feet (bcf)
1 cubic metre of crude oil	"	38 gigajoules of energy
1 kilowatt hour of electricity	"	3.6 megajoules of energy
1 tonne of coal	"	24 gigajoules of energy

Prefixes

Prefix	Multiple	Symbol
kilo	10^3	k
mega	10^6	M
giga	10^9	G
tera	10^{12}	T
peta	10^{15}	P
exa	10^{18}	E